An Assessment of the Impact of Climate Change on Hydroelectric Power

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Abstract

Global climate change is one of the greatest challenges of the twenty-first century. Rising temperatures and alteration of weather patterns are anticipated to result from increased atmospheric concentrations of greenhouse gases, caused, in part, by the use of fossil fuels for electricity generation.

Climate change is predicted to have major impacts on many aspects of human society from agriculture to water supply. The process of limiting the extent of climatic change began with the Kyoto Protocol, committing industrialised nations to modest cuts in their emissions. To achieve these and in the longer term, much greater cuts, electricity production must reduce its reliance on fossil fuels, by the increased use of renewable resources. Hydropower is currently the only major renewable source contributing to energy supply, and its future contribution is anticipated to increase significantly. However, the successful expansion of hydropower is dependent on the availability of the resource and the perceptions of those financing it.

Increased evaporation, as a result of higher temperatures, together with changes in precipitation patterns may alter the timing and magnitude of river flows. This will affect the ability of hydropower stations to harness the resource, and may result in reduced energy production, implying lower revenues and poorer financial returns. The continuing liberalisation of the electricity industry implies that, increasingly, profitability and the level of risk will drive investment decision-making. As such, investors will be concerned with processes, such as climatic change, that have the potential to alter the balance of risk and reward.

This thesis describes a methodology to assess the potential impact of climatic change on hydropower investment, and details the implementation of a technique for quantifying changes in profitability and risk. A case study is presented as an illustration, the results of which are analysed with respect to the implications for future provision of hydropower, as well as our ability to limit the extent of climatic change.

Declaration

I declare that this thesis has been completed by myself and that, except where indicated to the contrary, the research documented is entirely my own.

Gareth P. Harrison

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Abbreviations

AET	Actual Evapotranspiration
AGCM	Atmosphere General Circulation Model
ANN	Artificial Neural Network
AMIP	Atmospheric Model Intercomparison Project
ASL	Above Sea Level
BaU	Business-as-Usual
BCM	Billion Cubic Metres
BJVC	Batoka Joint Venture Consultants
BOOT	Build-Own-Operate-Transfer
BOT	Build-Operate-Transfer
CAPC	Central African Power Corporation
CAPM	Capital Asset Pricing Model
CCC	Canadian Center for Climate
CCGT	Combined Cycle Gas Turbine
CDM	Clean Development Mechanism
CET	Central England Temperature
CEGB	Central Electricity Generating Board
CFC	Chlorofluorocarbon
CfD	Contract for Differences
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COM	Component Object Model
COP	Conference of the Parties
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CRU	Climatic Research Unit, University of East Anglia, UK
CV	Coefficient of variation
CVM	Contingent Valuation Method
DC	Developing Countries
DDC	Data Distribution Centre
DP	Dynamic Programming
EBIT	Earnings Before Interest and Tax
EC	European Commission
ECHAM	European Centre/Hamburg Model (MPI)
ECU	European Currency Unit (Euro)
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency, Washington, USA

ESI	Electricity Supply Industry
EU	European Union
FAR	First Assessment Report
FGD	Flue Gas Desulphurisation
FS	Feasibility Study
GA	Genetic Algorithm
GCM	General Circulation Model
GDP	Gross Domestic Product
GFDL	Geophysical Fluid Dynamics Laboratory, Princeton, USA
GISS	Goddard Institute of Space Studies, New York, USA
GRDC	Global Runoff Data Centre
GtC	Gigatonnes of Carbon
GUI	Graphical User Interface
GWP	Global Warming Potential
HCFC	Hydrochlorofluorocarbon
HEC	Hydrologic Engineering Center, US Army Corps. of Engineers
IGCC	Integrated Gasification Combined Cycle
IPP	Independent Power Producer
IEA	International Energy Agency
IIASA	International Institute for Applied Systems Analysis
IPCC	Intergovernmental Panel on Climate Change
IRR	Internal Rate of Return
LDC	Less Developed Countries
LOLP	Loss of Load Probability
MARR	Minimum Acceptable Rate of Return
MITSIM	Massachusetts Institute of Technology River Basin Model
MPI	Max Planck Institute
NCAR	National Center for Atmospheric Research, Boulder, Colorado, USA
NCF	Nominal Cash Flow
NETA	New Electricity Trading Arrangements
NGC	National Grid Company
NPL	Normal Pool Level
NPV	Net Present Value
NO_x	Oxides of Nitrogen
OECD	Organisation for Economic Cooperation and Development
OFFER	Office of Electricity Regulation
OFGEM	Office of Gas and Electricity Markets
OGCM	Ocean General Circulation Model
O&M	Operations and Maintenance
OOP	Object Oriented Programming
PA	(Power) Purchase Authority
PE	Potential Evaporation
PET	Potential Evapotranspiration
PPA	Power Purchase Agreement
ppmv	parts per million by volume
ppbv	parts per billion by volume
PURPA	Public Utility Regulatory Policy Act
PV	Photo-Voltaics

REC	Regional Electricity Company
RMS	Root Mean Square
ROCE	Return On Capital Employed
RoR	Run of River
ROI	Return On Investment
SADC	Southern African Development Community
SAR	Second Assessment Report
SDP	Stochastic Dynamic Programming
SO_2	Sulphur Dioxide
UD/EP	Upwelling-Diffusion-Energy Model
UKMO	Meteorological Office, Bracknell, UK
UN	United Nations
UNEP	United Nations Environment Programme
UNESCO	United Nations Educational, Scientific and Cultural Organisation
UNFCCC	United Nations Framework Convention on Climate Change
WACC	Weighted Average Cost of Capital
WEC	World Energy Council
WMO	World Meteorological Organisation
WTA	Willingness to Accept
WTP	Willingness to Pay
ZESCO	Zambia Electricity Supply Commission
ZESA	Zimbabwe Electricity Supply Authority
ZRA	Zambezi River Authority

Symbols

α	Sub-surface Runoff Coefficient (mm/day)
β	Priestley-Taylor Coefficient
β_e	Equity Beta Coefficient
γ	Psychrometric Constant (kPa °C^{-1})
δ_T	Mean Diurnal Temperature Range (°C)
Δ	Gradient of the Saturated Vapour Pressure Curve (kPa °C^{-1})
ε	Surface Runoff Exponent
η	Turbine Efficiency
θ	Proportion of Debt
κ	Sub-surface Runoff Exponent
λ	Latent Heat of Vaporisation (MJ/kg)
μ	Mean
ρ	Correlation Coefficient
ϱ	Density of Water (1,000 kg/m^3)
σ	Standard Deviation
τ	Marginal Tax Rate
ϕ	Elasticity
A	Snow Accumulation (mm)
AET	Actual Evapotranspiration (mm/day)
A_h	Energy Advection (mm/day)
c_d	Cost of Debt (%)
c_e	Cost of Equity (%)
CF	Cash-flow
d	Discount Rate
D	Vapour Pressure Deficit (kPa)
e_s	Saturated Vapour Pressure (kPa)
E	Energy (J)
E_p	Potential Evaporation (mm/day)
E_{rc}	Reference Crop Evaporation (mm/day)
F	Fuel Cost (US$)
g	Acceleration due to Gravity (9.81 m/s^2)
G	Soil Heat Flux (mm/day)
H	Hydraulic Head (m)
i	Indices
I	Investment Cost (US$)
j	Indices
mf	Snowmelt Factor
M	Operations and Maintenance Cost (US$)
NS	Nash-Sutcliffe Criterion

O	Observed River Flows
P	Measured Precipitation (mm/day)
P_{eff}	Effective Precipitation (mm/day)
PET	Potential Evapotranspiration (mm/day)
q	Mean Flows
Q	Flow Volume (m^3)
r_e	Equity Rate of Return (%)
r_f	Risk-free Rate of Return (%)
r_m	Market Rate of Return (%)
R_n	Net Radiation (mm/day)
R_b	Baseflow (mm/day)
R_s	Surface Runoff (mm/day)
R_{ss}	Sub-surface Runoff (mm/day)
R_t	Total Runoff (mm/day)
S	Simulated River Flows
S_{max}	Maximum Soil Moisture Storage (mm)
S_o	Extraterrestrial Radiation (mm/day)
T	Temperature (°C)
T_l	Melting Threshold Temperature (°C)
T_s	Freezing Threshold Temperature (°C)
U	Wind Speed at 2m Height (m/s)
z	Relative Soil Moisture Storage

Contents Summary

Contents

List of Figures

List of Tables

Chapter 1

Introduction

1.1 Thesis Background

Global climate change is one of the most serious threats to the Earth and the greatest challenge facing human society in the twenty-first century. Rising temperatures and changes in precipitation patterns are expected to be the result of an enhanced greenhouse effect caused by excess atmospheric concentrations of carbon dioxide and other greenhouse gases. The enhancement has been caused by anthropogenic emissions since the Industrial Revolution, and currently around one third of emissions are attributed to fossil-fuelled electricity generation. With the accelerating industrial and economic development of many countries, electricity demand is expected to increase rapidly. If this occurs using conventional fossil-fuel technologies, the consequences for greenhouse gas levels may be significant.

The possibility of global temperature rise of between 1 and 4.5°C has led to considerable research effort into the effects of changes in temperature and other climatic variables. Studies suggest a wide range of detrimental impacts from rising sea levels, spread of vector borne diseases, increased storm activity and damage, and changes in the availability of water. The potential for significant disruption and losses to human activities have prompted unprecedented levels of activity from international agencies in order to find solutions to and agreement on the carbon problem.

The landmark agreement, the Kyoto Protocol, committed most Industrialised nations to modest cuts in their carbon emission levels by 2010, and forms the basis for reducing emissions beyond. The increased use of renewable energy sources is one of the key options available to mitigate climate change, and one of the many advantages is that they depend on natural climate for their fuel sources. However, changing climate will alter the quantity and availability of the resource and this will impact on energy production.

Hydropower is one such resource that could experience climatic feedback. This will occur through the alteration of river flow regimes by changes in precipitation together with increased water loss through evapotranspiration as temperatures rise. Reductions in river flow may lower production and consequently impact on electricity sales revenue and financial performance.

The increasing use of private capital in the electricity industry has altered the focus of electricity supply from the provision of a service to the need to make profits from the production and sale of a commodity. As such, the nature of generation investment appraisal has become concerned primarily with the balance between investment risk and reward. Therefore, processes such as climate change, that have the potential to alter this balance will be of importance to investors.

The possibility of lower expected financial performance as a result of climate change may make hydropower schemes less attractive, particularly given the large capital requirement relative to fossil-fuelled plant.

Where this leads to the postponement or abandonment of potential schemes, then other technologies will have to be used. If these are fossil-fuel based, then additional carbon dioxide will be released, potentially worsening the global warming impact.

Given that hydropower capacity is expected to increase threefold over the next century, and that some predictions implicitly rely on this, the effect of lower than anticipated investment in hydropower could have significant consequences.

1.2 Project Objectives and Scope

The project had several distinct objectives:

1. To gain an understanding of the climate change process, the evidence for it, and the projected future climate that may result.
2. To examine how electricity production contributes to global warming, and with reference to trends in electricity demand, supply and industry structure, to infer its future contribution, and the resultant climatic changes.
3. To explore the nature of climatic feedbacks on the electricity industry and in particular on hydropower.
4. To determine the current state of research into climate change impacts on hydropower, to identify key limitations and research needs and to devise a suitable methodology to be implemented in software form.
5. To use the software to explore and quantify the risk that climate change poses to hydropower production and particularly on its investment performance.

6. To indicate how changes in risk and perceptions of hydropower affect future provision worldwide, and the ability to constrain global emissions and greenhouse gas levels.

1.3 Thesis and Contribution to Knowledge

Overall, the project will test the hypothesis that:

> climate change will adversely affect production from hydropower schemes and consequently deter investment in them.

While considerable attention has been paid to the impact of climatic change on hydrology, and to a lesser extent on the operation of hydropower schemes, there is no corresponding investigation of impacts on profitability and investment viability.

Secondly, the relationship between climate and investment is not well understood, and this thesis goes some way towards correcting that.

It is anticipated that the techniques and analysis presented here will be understood and welcomed by those involved in climate change research, in energy policymaking, by investors, insurers, engineers and others involved in the planning, design and operation of electricity systems.

1.4 Thesis Outline

The thesis consists of eight chapters, together with necessary appendices.

Chapter 2 introduces the issue of climate change, its scientific basis and the evidence that climate change is both probable and underway. The means of modelling and projecting future changes are examined along with their limitations. Current 'best guess' projections are considered along with brief descriptions of potential climate change impacts.

Chapter 3 highlights the environmental impacts of electricity generation. The link to climate change and the means of mitigating the problem are examined. The determinants and form of future electricity demand is considered prior to a discussion of recent changes in the nature of the electricity supply industry (ESI) due to the re-introduction of private capital. The method and scope for private finance is analysed, before a description of the implications of the new industry structure for the provision of renewable energy.

Chapter 4 details the impact of climatic changes on the hydrological cycle and in particular on river flows. The resultant effects on hydropower potential and operation are also detailed. Limitations of existing studies in the literature are highlighted and a proposal made to examine, quantitatively, the impact on investment in hydroelectric power. Current methods of investment appraisal are noted and suggestions made as to their limitations in light of climatic change.

Chapter 5 specifies the analytical approach to be encapsulated in a software tool. Potential approaches are considered with a view to data availability, software complexity and modelling practicality.

Chapter 6 presents the theoretical and mathematical basis of the 'HydroCC' software tool, together with a detailed description of its structure, features and operation.

Chapter 7 describes the case study used to validate the methodology and software. The performance of the software in simulating the hydrology, operation and financial analysis is examined, prior to the presentation of the results from a variety of analyses.

Finally, Chapter 8 examines the results of the case study, their validity and their implications for a variety of issues on a regional and global basis. Several aspects of hydropower developments are considered in a series of strategies for dealing with the issue of climatic change. Lastly, conclusions are drawn regarding climate change, the future of the electricity industry and the role of hydropower, and several suggestions are presented as to possible future work on this subject.

Chapter 2

Global Climate Change

Global climate change or global warming was one of the key scientific and political challenges of the 20th century and will become increasingly so in the 21st. Accordingly, the Intergovernmental Panel on Climate Change (IPCC) was established in 1988 by the World Meteorological Organisation (WMO) and the United Nations Environment Programme (UNEP). It was set several key tasks:

1. to assess scientific information relating to climate change,
2. to assess its environmental and socio-economic consequences,
3. to formulate response strategies for the management of the issue.

Working Groups were formed to deal with each area. Working Group I reported in 1990 as part of the First Assessment (FAR) and featured state of the art research from key experts in fields relevant to the science of climate and climatic change [1]. In its 1995 report the IPCC significantly stated: 'the balance of evidence suggests a discernible human influence on the climate system' [2].

This chapter summarises the key ideas and evidence that led the IPCC to this conclusion. Several distinct topics are covered: the linkage between carbon dioxide and other gases and global climate change; observational evidence for such change; methods and limitations of predicting future climates; predictions of future climate and the resulting impacts; and finally how the issue of climate change is being dealt with.

2.1 The Science of Climate Change

2.1.1 The Climate System

Climate is defined as average weather over a period of time for a particular geographical region. Climate variations are caused by the interaction of the atmosphere with other components of the climate system, which include the oceans, land, snow and ice, and hydrological systems.

The Earth's climate is driven by the output of the Sun, and variations in its output, together with the rotation and orbit of the Earth, influence climate. The average incident solar energy on the Earth is 342 W/m^2. Around 31% of this is scattered or reflected back to space by the atmosphere, leaving the remainder to heat the surface and atmosphere. To balance this, the Earth radiates longwave infra-red energy. The amount of infra-red energy emitted depends on the temperature of the emitting body. For an absorbing surface to emit 236 W/m^2, its temperature would have to be around -19°C. As the Earth's surface is on average 33°C warmer, the atmosphere is artificially warming the Earth. This blanketing effect, known as the 'Greenhouse Effect' was first recognised by Fourier in 1827 [3].

Whilst the atmosphere consists mainly of nitrogen and oxygen (99%), it is the presence of small quantities of certain 'greenhouse' gases that are responsible for the blanket effect. These gases are transparent to the incoming shortwave solar radiation, but absorb and re-emit longwave radiation such as that emanating from the Earth's surface. The re-emission occurs in all directions, with some downwards warming air, land and water below. The process is natural and has been occurring for at least two billion years, with small quantities of mainly water vapour and carbon dioxide (CO_2) trapping sufficient heat to allow water to exist in the liquid phase and creating conditions suitable for life.

Since the 1950s concern has been expressed about rising atmospheric concentrations of CO_2 and other gases, together with increasing global mean temperatures. The possibility of an 'enhanced' greenhouse effect has led to an unprecedented investigation into the cause and possible effects of the rises [3].

Since pre-industrial times, around 1750, there has been a 27% increase in atmospheric concentrations of CO_2, rising from 280 ppmv to 366 ppmv in 1998. As shown in Figure 2.1, measurements from air trapped in Antarctic ice, together with direct measurements from Mauna Loa in Hawaii indicate an exponential growth rate in CO_2 concentrations, particularly in the latter half of the twentieth century.

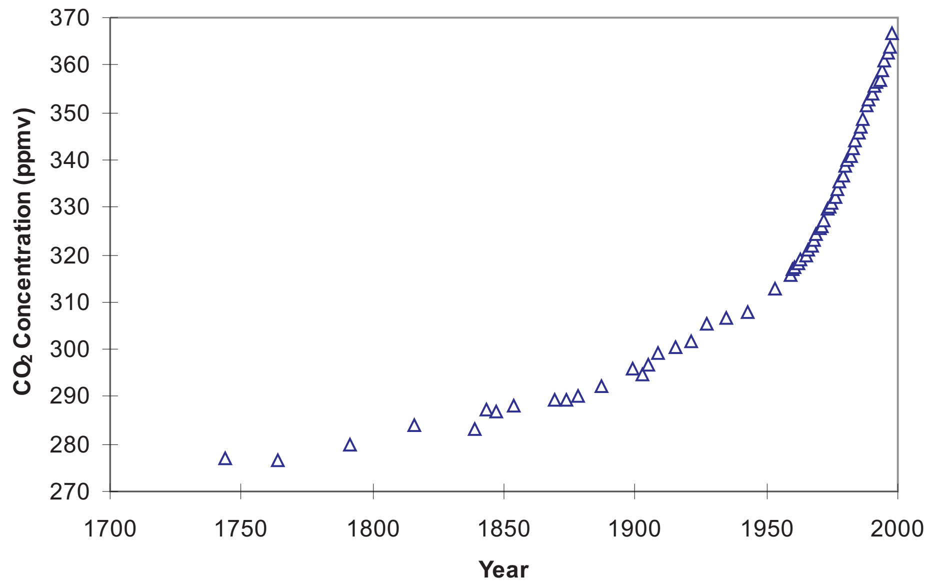


Figure 2.1: Atmospheric CO_2 increase over the past 250 years, indicated by air trapped in Antarctic ice (up to 1953) and by direct measurement at Mauna Loa, Hawaii from 1958 onwards [4, 5].

2.1.2 The Carbon Cycle

Carbon, in the form of CO_2, carbonates and organic compounds, is continuously exchanged between a number of reservoirs: atmosphere, oceans, living organisms, and over long time scales, sediments and rocks. Figure 2.2 illustrates this. The largest fluxes are between the atmosphere and land vegetation, and the atmosphere and the ocean surface. The exchanges between carbon reservoirs are quite small compared to the size of the reservoirs themselves, with the atmosphere, soil, surface ocean and deep ocean estimated to hold 750, 2,190, 1,020 and 38,100 gigatonnes of carbon (GtC) respectively [6]. Whilst the anthropogenic fluxes of fossil fuel combustion and deforestation are significantly smaller than the natural ones, their effects are sufficient to alter the balance.

Fossil Fuel Emissions

Since 1751 the combustion of fossil fuels has released over 265 GtC into the atmosphere, with half of the emissions occurring since the mid 1970s. The 1996 CO_2 emissions estimate was 6.5 GtC, at that stage the highest ever, and showed a small (1.7%) increase over the 1995 total. Figure 2.3 shows the exponential growth since 1820, which averaged 4% a year despite interruptions due to both World Wars and the Great Depression. The oil crisis of the 1970s saw growth fall to 2%, with no

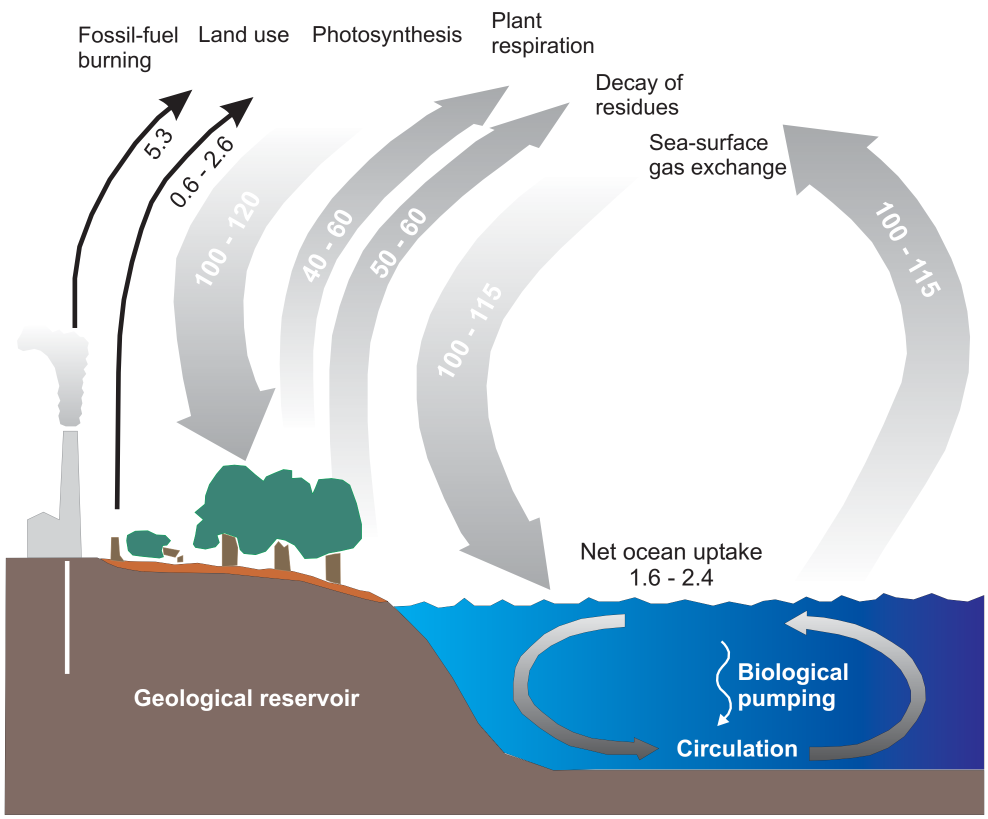


Figure 2.2: Global carbon cycle and annual flows. GtC/yr over 1980-1989 [7]

increase from 1979-1984. 1990-1993 saw declining emissions, interrupting the trend of modest growth [8, 9].

Figures for 1996 indicate that liquid and solid fuels accounted for 77.5% of the emissions from fossil-fuel burning in 1996, with gas fuels representing 18.3%, the balance caused by cement production and gas flaring. The share of gas is gradually growing as natural gas use increases (*e.g.* electricity generation) [9]. Chapter 3 details the energy related emissions in more detail.

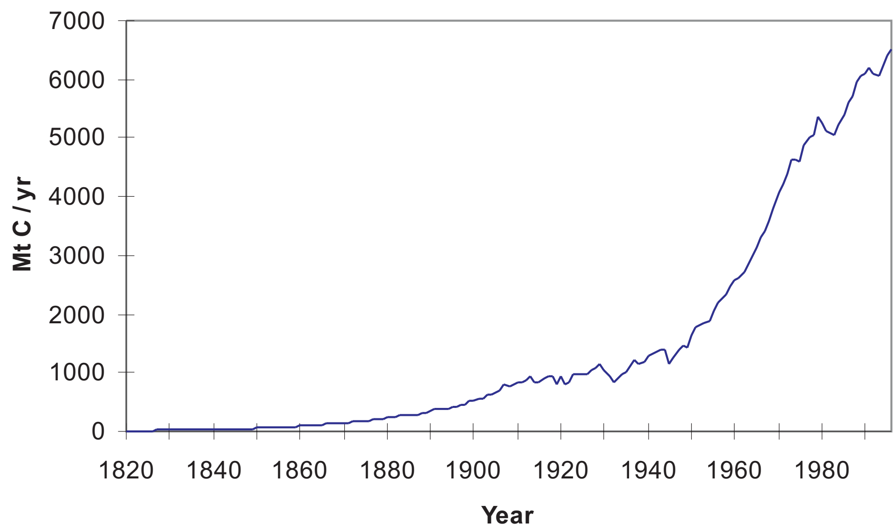


Figure 2.3: Global carbon emissions from fossil fuel combustion and cement production. MtC/yr over 1820-1996 [9]

Land-use Change

The second most important anthropogenic effect has been due to changing land-use, particularly in tropical regions. The soil and vegetation of natural (or unmanaged) forests are estimated to hold between 20 and 100 times the amount of carbon per unit area than agricultural land. The demand for agricultural land has followed increasing population. Until the middle of the twentieth century this was the prime driver behind deforestation, but more recently, the exploitation of minerals and timber have seen the clearance of enormous areas of forest.

It is estimated that since 1850 the cumulative release of carbon to the atmosphere through changing land-use, and in particular deforestation, has been in the region of 115 ± 35 GtC [10]. Releases have occurred due to burning (*e.g.* slash-and-burn in the Amazon), decay of biomass on-site, the oxidation of wood products, for example in paper making, and the oxidisation of carbon in the soil. The regrowth of trees and the replacement of organic material have partly offset the releases.

The pattern of change has altered, as during the nineteenth and early twentieth century most of the releases came from temperate regions, whilst from 1950 onwards the major source is deforestation in the tropics. The clearance of large swathes of the Amazon basin for grazing and mineral exploitation is well documented [11]. The severe smogs seen over much of south-east Asia in the late 1990s were the result of deliberate land clearances in Indonesia [12].

Missing Carbon Sink

The releases from anthropogenic sources have increased the atmospheric concentrations of carbon dioxide. However, the increase from 288 ppmv in 1850 to 366 ppmv in 1998 does not represent the accumulation of the cumulative releases. In fact, only around 48% of the releases have added to atmospheric concentrations. The IPCC First Assessment described how simulations using historic emissions estimates tended to overestimate the atmospheric concentrations. This represented a 'missing carbon sink' and could not be accounted for by the uptake of carbon in the oceans [8]. Additional work on this aspect has identified several sinks, not least the uptake by Northern Hemisphere forest regrowth, but also enhanced forest growth due to CO_2 fertilisation, nitrogen deposition and potentially response to changes in climate. There is some uncertainty surrounding the magnitude of the sinks [6]. Table 2.1 shows the average Carbon Budget for the 1980s and the imbalance term represents the 'missing' sinks excluding the forest regrowth which is identified explicitly.

CO_2 Flow	GtC/yr
Sources:	
Fossil fuel combustion and cement production	5.5 ± 0.5
Deforestation and land-use change	1.6 ± 1.0
Sinks:	
Storage in the atmosphere	3.3 ± 0.2
Ocean uptake	2.0 ± 0.8
Uptake by Northern Hemisphere regrowth	0.5 ± 0.5
Net imbalance:	1.3 ± 1.5

Table 2.1: Average annual budget of CO_2 flows for 1980-1989 [8, 6]

2.1.3 Linking Carbon and Climate

The discussion of increasing atmospheric carbon concentrations is based on the premise that increased CO_2 implies increased temperatures. Instrumental records indicate rising temperatures and CO_2 concentrations, however, some commentators argue that this may simply be a coincidence, or a result of other factors (*e.g.* Sun's cycle). A conclusion as to whether a correlation exists cannot be made on the basis of data from the past few hundred years; it is necessary to look at long term indices of CO_2 and temperature. The key evidence is contained in the Antarctic ice. Recent cores taken at Vostok allow the measurement of CO_2 concentration from air trapped in the ice which dates back over 400 thousand years and incorporates 4 glacial periods. In addition, by sampling the deuterium concentrations an estimate of temperature can be made [13, 14].

Figure 2.4 shows both sets of data from the last 160 thousand years, and indicates a correlation between Antarctic temperature, inferred from deuterium concentrations, and CO_2 concentrations. It can be seen that sharp changes in temperature are generally accompanied by similar changes in CO_2.

2.1.4 Key Greenhouse Gases

Although the discussion has so far concentrated on carbon dioxide, it is by no means the only greenhouse gas. In addition to water vapour, other natural and man-made compounds have potential to enhance the greenhouse effect. Different compounds absorb radiation in particular wavelength bands, so increasing concentrations of compounds that are radiatively active in the infrared range will decrease the radiation leaving the Earth, consequently warming it. The properties of some of the most important are shown in Table 2.2.

Atmospheric Parameter	CO_2	CH_4	CFC-12	HCFC-22	N_2O
Concentration (ppbv):					
Pre-industrial	280,000	700	0	0	275
Current (1992)	355,000	1,714	0.503	0.105	311
Accumulation rate (%/yr)	0.4	0.8	4	7	0.25
Lifetime (years)	50-200	12-17	102	13	120

Table 2.2: Summary of key greenhouse gases [15]

Methane (CH_4) is produced naturally, but anthropogenic sources including fuel production, cattle farming, landfill and deforestation (biomass burning and decay), are increasing its atmospheric concentrations by around 0.8% annually. Methane has a much shorter atmospheric residence time and is removed from the atmosphere

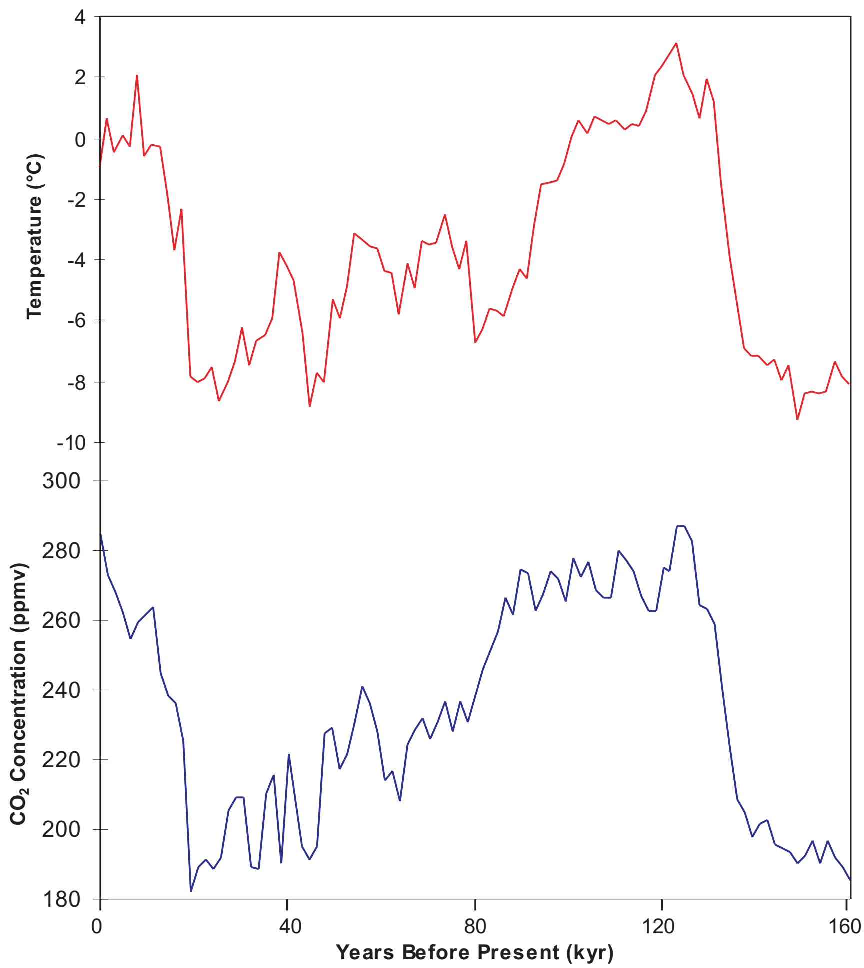


Figure 2.4: CO_2 concentration (bottom) and temperature changes over last 160,000 years, indicated by ice core from Vostok, Antarctica. Temperature changes estimated from deuterium concentrations. Years are years before present (BP) [13, 14]

through reactions with the hydroxyl radical (OH). As many hydro- and halo-carbons also react with OH, increasing methane concentrations reduces the ability of the atmosphere to remove greenhouse gases, and around 30% of increases in methane concentration can be attributed to this.

Nitrous Oxide (N_2O) is naturally occurring, but its concentrations have also risen through fertiliser use and fossil fuel combustion.

Chlorofluorocarbons (CFCs) are entirely man-made and were used in refrigeration and as a propellant. The two most important, in terms of their warming contribution are CFC-11 and CFC-12. Their ability to trap radiation is tens of thousands of times greater than CO_2. They were banned by the Montreal Protocol due to evidence of damage to the ozone layer, and their concentrations have now begun to fall. However, concentrations of hydrofluorocarbons (HCFCs) introduced to replace CFCs, are increasing and these have similar radiation trapping properties, although they do not damage the ozone layer [16].

Water vapour is a key greenhouse gas. As the atmosphere warms its ability to hold water increases, so the natural quantity of water vapour will increase and create a positive feedback.

Aerosols are particles suspended in the atmosphere that alter the energy balance by absorbing or scattering incoming radiation and tend to cool the atmosphere. Natural sources include dust blown from the land surface, from forest fires, and occasionally from volcanic eruptions. Man-made sources include biomass burning (*e.g.* forest clearance), but are dominated by sulphate particles resulting from the formation of sulphur dioxide (SO_2) from fossil fuel combustion. The short residence time means that the effect tends to be regional rather than global. The net effect of anthropogenic sulphates is estimated to reduce global radiation by around 0.5 W/m^2, partially offseting the CO_2 increases [3].

Aerosols also affect climate indirectly, through their effect on cloud formation. The presence of large numbers of aerosol particles during cloud formation produces clouds that are more reflective to sunlight and increase the global energy loss by 0-1.5 W/m^2. Despite rising coal use, particularly in Asia, SO_2 emissions are expected to fall as reduction measures first used in Western countries are extended worldwide. As a result, it is expected that there will be fewer sulphate particles to offset the CO_2 increases [3]. For detailed treatment of aerosols see Houghton *et al* [15].

2.1.5 Radiative Forcing

Radiative forcing is the term used to describe the imbalance between absorbed solar energy and radiation emitted to space by the Earth. Any process that has the ability to create a radiative imbalance is known as a radiative forcing agent. In addition to changing concentrations of greenhouse gases, radiative forcing agents include solar radiation, direct and indirect aerosol effects, and surface albedo (reflectivity). Radiative forcing can be defined as the change in net radiation and is measured in W/m^2. Positive values indicate warming, and vice versa.

The radiative forcing due to each gas is calculated with radiative transfer models, which account for the complicating factor of overlapping absorption spectra. The existing concentration of a gas determines how additional molecules will affect radiative forcing. Abundant gases require a greater increase in concentration to cause additional forcing, whilst scarce gases (*e.g.* HCFCs) have a near linear concentration-forcing relationship. As such, the forcing effect of CO_2 is found to be related logarithmically to the concentration.

Carbon dioxide has a relatively low radiative forcing effect, but as it is by far the most abundant greenhouse gas, it is convenient to measure the forcing potential of other gases relative to it. This can be on a molecular basis or in terms of unit mass, and is shown, for several key gases, in Table 2.3 (note the high forcings of the halocarbons). The relative warming effect of greenhouse gases depends on the time frame used. A gas with a strong radiative effect but short lifetime will have a greater effect in the short term, than a weaker but longer-lived gas. Over time however, the weaker gas will have more of an effect. Overall, since pre-industrial times CO_2, CH_4, N_2O and halocarbons are estimated to contribute a forcing of 2.45 W/m^2 [6].

	CH_4	N_2O	CFC-11	CFC-12	HCFC-22
Per Molecule	21	206	12,400	15,800	10,700
Per Unit Mass	58	206	3,970	5,750	5,440

Table 2.3: Radiative forcing relative to CO_2 per unit molecule and per unit mass change in 1990 concentrations [16]

Global Warming Potential

Global Warming Potential (GWP) is defined as the time integrated commitment to climate forcing from the instantaneous release of unit mass of a trace gas relative to unit mass of carbon dioxide [16]. It is intended as a simple means of describing the relative ability of trace gas emissions to affect radiative forcing. However, there are difficulties in determining trace gas GWPs, primarily uncertainty over atmospheric lifetimes. Their use is limited as application to unevenly distributed gases or aerosols is difficult, they do not consider feedbacks and reflect global averages only [15]. Despite these problems, and as Table 2.4 shows, they are quite illustrative in explaining the relative effect of different gases on global warming. Other gases possess even greater GWPs, for example, sulphur hexafluoride (SF_6), used in electrical circuit breakers, is estimated to have a GWP of 23,900 and an atmospheric lifetime of 3200 years [6].

	CO_2	CH_4	N_2O	CFC-11	CFC-12	HCFC-22
100 Year GWP	1	21	310	3,500	7,300	1,700
Emissions (Mt/yr)	26,000	300	6	0.3	0.4	0.1
Percentage Effect	61	14	4	2	7	0.4

Table 2.4: Summary of key greenhouse gas Global Warming Potentials [16]

2.1.6 Climate Feedback

There are several feedback mechanisms that complicate the issue of climate change, and how to predict it. These are the water vapour, snow-ice albedo, cloud and ocean-circulation feedbacks.

A warmer atmosphere can hold more water vapour, which is itself a greenhouse gas, and creates a positive feedback. In addition, as water vapour absorbs incoming solar radiation the increased quantity provides an additional heating effect. Estimates and satellite measurements suggest that for a warming of 1.2°C, these effects increase warming by a factor of 1.6 (to 1.9°C) [17]. Although the water vapour feedback is well understood in general terms, the precise nature of it is difficult to model, especially in respect to processes in tropical regions [18].

A warmer planet has less snow and ice cover which results in a lower albedo or reflectivity, and hence an increased absorption of solar radiation. The positive feedback due to the reduction in snow and ice cover would, on its own, amplify the average temperature rise due to a doubling of CO_2 by 20% [3].

Although the presence of clouds creates a cooling of the atmosphere, a number of different processes contribute to the effect. The clouds inhibit infra-red re-emission (cloud radiative forcing) compared to clear skies, creating a warming similar to greenhouse gases. Conversely, they cool the atmosphere by reflecting solar radiation, and this effect predominates. Cloud feedback mechanisms are extremely complex, and changes in cloud amount, altitude and water content are possible effects of global warming. It is overly simplistic to suggest that, for example, an increase in cloud cover would help offset greenhouse gas warming, as the interplay of the two processes may result in a fall in net cooling (*i.e.* a warming effect) [17]. There have been improvements in the understanding of many of the component processes involved but there are still differences between modelling groups concerning the magnitude and sign of the overall feedback effect [18].

The oceans are key in determining the Earth's climate, and will have an important role in determining the effect of anthropogenic climate change. They are the main source of atmospheric water vapour which, due to latent heat released in cloud condensation, is the largest heat source for the atmosphere. The large heat capacity tends to smooth the extremes and will control the rate of change. Ocean circulation redistributes heat from the equator to polar regions, and slight changes in distribution could have profound effects on climate [3]. Evidence suggests that during the last ice age, the circulation of the Gulf Stream, which moderates the climate of western Europe and the UK in particular, was altered [19]. Climate warming could result in the Gulf Stream moving to the south and causing regional cooling in the UK.

2.2 Observational Evidence for Climate Change

Some of the key questions in examining observational evidence for climate change are: has the climate warmed, become wetter, more variable or extreme, and is 20th century warming unusual?

The answers to these questions are dependent on the availability of quality data, and to this end there has been a large increase in the quantity and variety of climate data being measured, terrestrially, from satellites and from the oceans. The principal reason is to detect climate change due to global warming through an increase in temperature and changes in other climate variables in the instrumental record. The requirement is to detect the global warming 'signal' among all the noise.

2.2.1 Temperature Rise

Global Temperatures

Globally averaged surface air and sea temperature has risen by between 0.3 and 0.6°C since 1850 [1, 20]. Over the 40 years to 1995, when data is more credible (with improved measurement coverage), the increase has been 0.2 to 0.3°C, with greater warming over the continents in the Northern Hemisphere. The warming is not uniform, and some regions have cooled. There has also been a reduction in the diurnal difference between maximum and minimum temperatures, mostly due to rising night-time minimum temperatures [21].

Figure 2.5 shows the combined global land and marine surface temperature record from 1856 to 1999. Compiled jointly by the Climatic Research Unit (CRU) and the

UK Meteorological Office (UKMO), the record is being continually up-dated and improved. The 1990s was the warmest decade in the series. The warmest two years of the entire series were 1997 and 1998, with the latter the warmest at 0.57°C above the 1961-90 mean. The six warmest years globally have now occurred in the 1990s. They are, in descending order, 1998, 1997, 1995, 1990, 1999 and 1991 [22].

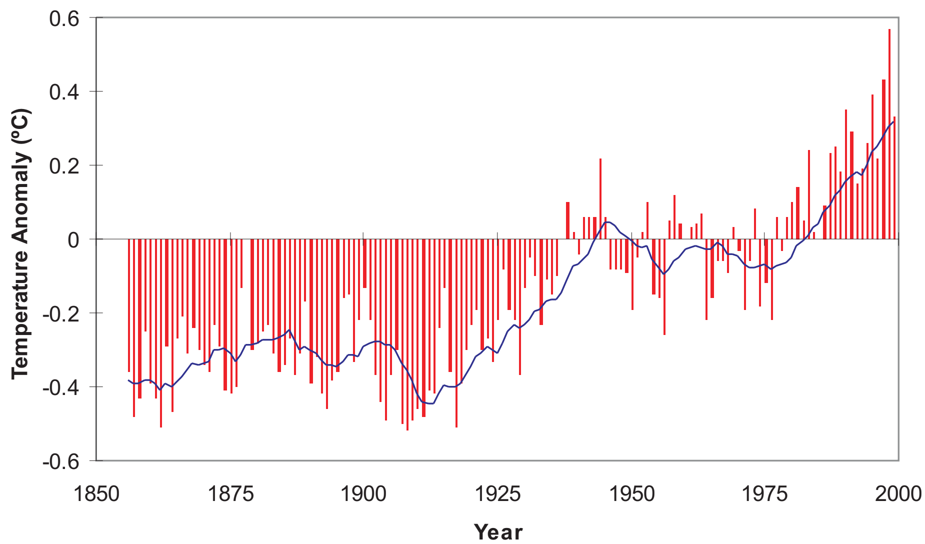


Figure 2.5: Measured temperature anomaly over last 150 years relative to 1961-90 mean. Solid line represents 10 year running mean [22]

Central England Temperature

The Central England Temperature (CET) is a record of temperatures which represent the average of an area between Manchester, Bristol and London. Measurements began in 1659 and it is the longest running instrumental record available. Originally complied by Manley in 1973 [23], it is now continually updated by the UK Meteorological Office. Recent data suggests that 1999 was 1.16°C above the 1961-90 average, the warmest year recorded in 341 years.

Millennial Data

Analyses of proxy climate series (from trees, coral, ice cores and historical records) show that the 1990s is the warmest decade of the millennium and the 20th century the warmest century. The warmest year of the millennium was 1998. Figure 2.6 shows the Northern Hemisphere temperature reconstructed from proxy sources and indicates the level of climate variability over the last Millennium. Temperatures in the early part of the Millennium are similar to mean 20th century, but the temperatures of the late 20th century are considerably higher. The warming since 1850 is in marked contrast to the prior trend of cooling of around 0.02°C/century, which is reputed to be due to changes in the Sun's output. However, despite the extensive variety of proxy sources, more widespread high-resolution data will be required before the conclusions can be relied on [24].

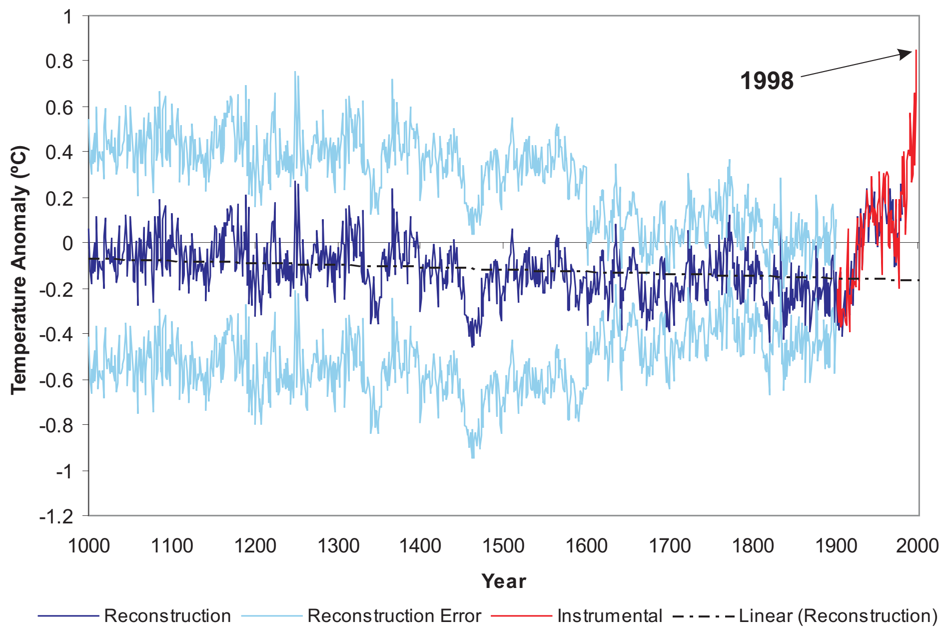


Figure 2.6: Northern Hemisphere temperature anomaly over last Millennium reconstructed from proxy sources (relative to 1902-1980 mean) [24]

Indirect Measures

Indirect measures provide support for the notion of rising temperatures, but as they are influenced by other factors, they cannot individually confirm the trend. Evidence includes: glacial retreat in the 20th century is of the scale expected for warming of 0.6-1.0°C; records dating from 1870 suggest that coral reef bleaching has been more prevalent from 1979 (bleaching is associated with high temperatures as well as other environmental factors like pollution); and an analysis of the CET indicated a phase shift in the annual temperature cycle, but this was not confirmed by later studies [21].

2.2.2 Precipitation Change

Precipitation has increased in the mid to high latitudes of the Northern Hemisphere, whilst for the tropics and mid-latitudes of the Southern Hemisphere precipitation has fallen. Such changes are associated with rising temperatures since the 1970s. Overall there has been a 1% increase in global precipitation over land during the 20th century, although precipitation has been low since 1980 [21]. The changes in precipitation are more complex than temperature changes, and as such, it is difficult to draw more detailed conclusions.

Lack of long-term data on snow cover and snowfall has limited the study of changes in snow. Satellite data shows that snow cover on land in the Northern Hemisphere has decreased on average by 10% from 1988 to 1994. Spring cover is particularly affected, autumn and summer less so, whilst winter cover decrease is small. The decreases are strongly linked to rising temperature, and this is reflected by earlier spring thaws and a smaller percentage of precipitation falling as snow. Changes in snow cover are particularly important as snow is an important radiation reflector, and it is suggested that loss of snow cover may account for half of the springtime warming in the Northern Hemisphere since the 1970s [21].

2.2.3 Variability and Extremes

There is no consistent trend in temperature variability, and few regions have been examined for rainfall variability. Rainfall intensity trends are not consistent except in some areas, like the USA, where evidence suggests increases in intensity and extreme event frequency. There is no evidence of an overall increase in extreme weather or variability during the last century, but such evidence exists on a regional level.

2.2.4 Was Warming During the 20th Century Unusual?

Evidence presented in this section suggests that temperature is increasing, and that temperatures are the warmest seen for at least the last 1000 years. Whilst rapid climatic changes can occur naturally, in the last 10,000 years temperatures have been far less variable, and as such the recent warming appears anomalous. Whether or not the warming can be considered as a 'footprint' of climate change is currently under debate [25]. It seems likely that as more and more evidence indicating warming becomes available over the next decade or so, it will be possible to conclude that Man is to blame.

A more detailed description and discussion of observed climate variation can be found in Folland *et al* [26] and Nicholls *et al* [21], among others.

2.3 Predicting Climate Change

So far the discussion has been related to how climate change could be caused, and whether we can already see evidence of it. To be able to deal with it effectively we need quantitative information of how it could manifest itself. It is necessary to understand how to predict - or more accurately, project - climatic changes; to consider the strengths and weaknesses of various approaches and to examine the current consensus concerning future temperature rise.

Several methods have been used to predict future climate:

1. palaeo-analogue methods which estimate future climate change from past climates using proxy data,
2. simple global-average models,
3. simulations with General Circulation Models (GCMs).

The first method attempts to determine the sensitivity of climate to CO_2 concentrations from estimates of CO_2 concentrations and global average temperatures during periods in the past. Adjustments in prevailing temperature have to be made to account for differences in the Sun's radiance and in the Earth's albedo due to altered land-ocean proportions. One study suggested that the sensitivity was $3 \pm 1°$C, which is comparable to results from GCMs. If the palaeo-climatic reconstructions are accurate and extensive, then they may provide reasonable estimates of spatial patterns of change, but the method is weakened due to factors that include: uncertainties in climate reconstruction, limited areal coverage and influences of other factors involved in past climatic change [17].

The second method uses simple global-average models of the carbon cycle to determine future concentrations of CO_2 [27]. At present this is the standard method used in the IPCC assessments to indicate future temperature rise [28, 20, 29]. However, despite the use of simpler methods in the IPCC assessments, the more promising method in the long-term is the use of General Circulation Models.

2.3.1 General Circulation Models

General Circulation Models are complex numerical models of the atmosphere (AGCM) and the oceans (OGCM). Derived from weather forecasting models, they use the laws of conservation of momentum, heat and mass to describe the behaviour of the atmosphere and ocean. The horizontal variation of the variables in each layer is determined either at particular grid points defined by latitude and longitude (for finite difference models), or by a number of mathematical functions in spectral models (which use Fourier Series expansions). The time step required to ensure the solution is stable must be smaller than a value specified either by the fastest moving disturbance or wave, or the grid size. The greater the spatial resolution the smaller the required time step, and the greater the computing load. Current models use the fastest computers available and operate at over 10^{12} floating-point operations per second (flops) [3]. Table 2.5 shows the resolution of the current generation of ocean and atmosphere GCMs. The spatial resolution of the UKMO model is one of the best but still represents a region at the Equator of 260 by 400 km.

Group	Country	AGCM Resolution		OGCM Resolution	
		Horizontal	Vertical	Horizontal	Vertical
CCC	Canada	$3.7° \times 3.7°$	10	$1.8° \times 1.8°$	29
CSIRO	Australia	$5.6° \times 3.2°$	9	$3.2° \times 5.6°$	12
GISS	USA	$4° \times 5°$	9	$4° \times 5°$	16
MPI	Germany	$5.6° \times 5.6°$	19	$2.8° \times 2.8°$	9
NCAR	USA	$4.5° \times 7.5°$	9	$1° \times 1°$	20
UKMO	UK	$2.5° \times 3.8°$	19	$2.5° \times 3.8°$	20

Table 2.5: Coupled atmosphere-ocean General Circulation Models [30]

The limited resolution of AGCMs means that a number of important processes are not determined explicitly. Their effects are incorporated by relating them to the key variables which are wind, temperature, humidity and surface pressure. Parameterisation of the processes is based on observation and theory, and is one of the limiting factors in GCMs. Parameterisation schemes vary between models and are one of the major targets for criticism. Processes that are parameterised include radiation and cloud effects, land surface processes (*e.g.* soil moisture and river flow), and sub grid-scale heat, momentum and mass transport. Ocean models are similar to atmospheric ones except that water vapour balance is replaced by salinity. Models of oceanic carbon dioxide transfer are already used, and atmospheric chemistry are also expected to be used in GCMs in the near future, for example in the UKMO model [31].

AGCMs and OGCMs have tended to be operated separately, but a more realistic simulation can be carried out by coupling them. This has only really become possible with the increase in computing resources. However, there are still limitations. Apart from the computing load, the time mismatch between the atmosphere and ocean models (which have longer time steps) is problematic. Additionally, when the models are coupled, each tends to 'drift' to an erroneous state, as there is no constraint from ocean surface observations. Whilst 'flux correction' aims to stop drift, this is not guaranteed and the corrections are based on present-day conditions.

More detail on GCM structure, their processes and parameters and their caveats can be found in Cubasch and Cess [17] and Dickinson *et al* [18].

2.3.2 The Use of General Circulation Models

Whilst climate models have significant limitations, they are an extremely powerful means of studying climate and changes in it. They are used for determining climate sensitivity to various factors and more importantly in providing 'predictions', or more accurately 'projections' of future climate. The first step is to perform a 'control' simulation with parameters chosen to suit current climate. This allows a reference climate to be established and its statistical properties to be determined. These can be used to evaluate model performance against observations and to examine the response of the climate to altered parameters, for example, CO_2 concentration. The response must be compared with the 'natural' variability and an assessment made of whether the changes are due to change in climate, or the natural variability of the model. Two types of responses are considered: 'equilibrium' and 'transient'.

Equilibrium experiments compare the difference between simulations of climate with current levels of CO_2 and doubled CO_2, respectively called $1 \times CO_2$ and $2 \times CO_2$ scenarios. The resulting temperature difference between the two simulations is referred to as the model's climate sensitivity, and is defined as the temperature rise for a doubling of CO_2. The range of sensitivities exhibited by GCMs is from 2.1 to 4.6°C [29]. The simulations are run for a length of time sufficient for an equilibrium to be achieved. For a fully coupled GCM the equilibrium response time would be around 1000 years, but simpler models allow convergence in decades.

Whilst equilibrium response is suitable for model comparison, the results may be misleading as CO_2 concentrations will not undergo a step change. To get more realistic projections transient or time-dependent experiments are performed. These use gradually changing CO_2 concentrations, which enable the slow process of ocean heating to determine the timing of the response [17].

2.3.3 Model Evaluation

Differences in simulation may be due to the relative importance of different parameterisations, or relative strength of feedback mechanisms. Two GCMs that give seemingly similar equilibrium changes may do so for entirely different reasons. Understanding and modelling of climate processes have improved greatly in the five years between the IPCC assessments, and as a result the inter-model parameter differences are smaller. Despite that, some aspects of the climate mechanism are still not well modelled, in particular those related to clouds [17].

Many examples of individual climate model evaluation exist in the literature, although attempts to standardise their comparison has occurred only recently. Generally, the ability of climate models (especially AGCMs) to simulate mean distributions of climate variables has increased steadily. The IPCC Second Assessment Report (SAR) described comparisons between different coupled and component atmosphere GCMs in simulating current climate.

Coupled models, on average, simulated the large scale seasonal distribution of surface air temperature very well. Compared to observations, the discrepancies were largest over land and in particular over mountainous regions. The lack of aerosol forcing may account for some of the differences. The globally averaged mean model temperature agrees well with observations (12.2°C against 12.4°C for December-February), with Table 2.6 indicating that the range of values from the models was around 5°C. Precipitation is less well simulated, but the basic pattern is reproduced. The largest model differences occur in the tropics, and this is reflected in the spread of globally averaged model means, again shown in Table 2.6. Higher mean temperatures appear to be associated with increased precipitation rates. Coupled models simulate mean sea level pressure well, but appear to have difficulty reproducing seasonal snow and ice cover, which has implications for the snow-ice feedback mechanism [21].

Group	Surface air temperature (°C)		Precipitation (mm/day)	
	DJF	JJA	DJF	JJA
CSIRO	12.1	15.3	2.73	2.82
GFDL	9.6	14.0	2.39	2.50
GISS	13.0	15.6	3.14	3.13
NCAR	15.5	19.6	3.78	3.74
UKMO	12.0	15.0	3.02	3.09
Observed	12.4	15.9	2.74	2.90

Table 2.6: Coupled model simulated global average temperature and precipitation (DJF = Dec-Feb, JJA = Jun-Aug) [30]

Coupled model reproduction of regional climate is affected by the coarse spatial resolution of GCMs which prevents realistic modelling of mountains and coastlines. In the mean-time reasonable regional climate reproduction can be gained with a high-resolution model 'nested' within a limited part of the globe, and driven by boundary conditions gleaned from observation or from GCMs. This implies that as GCM resolution increases improved regional performance will result [21].

The IPCC Second Assessment presents the results of a comparative study of atmospheric models carried out for the Atmospheric Model Intercomparison Project (AMIP) [32]. All models used standard conditions of CO_2 concentrations and other factors. Table 2.7 provides a summary of several key climatic variables. It can be seen that the models simulation of pressure is accurate, whilst temperature and precipitation are less so. Once again the simulation of clouds is shown to be a problem.

	DJF		JJA	
	North	South	North	South
Mean sea level pressure (mb)	1.4	1.4	1.3	2.4
Surface air temperature (°C)	2.4	1.6	1.3	2.0
Precipitation (mm/day)	0.80	0.71	0.62	0.77
Cloudiness (%)	10	21	14	16

Table 2.7: Root mean square error between observed variables and mean AGCM simulation [30]

Treatment of clouds, the hydrological cycle and land surface processes are the source of the greatest uncertainty in climate models, and are responsible for most of the differences between models. Confidence in the results of climate models depend on their ability to simulate current climate and on realistic models of physical processes, and it is believed that the development of more representative and accurate coupled models offer the best method for understanding and predicting future climate [30].

2.3.4 Projections of Future Climate

Scenarios of Change

To be able to determine the timescale of future climate change from climate models it is necessary to supply projections of future emissions in greenhouse gases. Future emissions of CO_2 and other greenhouse gases will depend on rates of economic growth, population growth, energy resource availability, technology and the climate policies of national governments and international institutions.

The IPCC First Assessment used four emissions scenarios to evaluate the effect of different technology use and changes in emissions. Developed by Working Group III, the economic and population growth rates were the same for all four. The first was named the Business-as-Usual (BaU) scenario (or scenario A) and indicated emissions growth under policies and practices similar to those existing around 1990. Energy supply was assumed to be predominantely coal-based and there would be little improvement in efficiency, deforestation would continue apace and CFCs would be only partially phased out. Under this scenario CO_2 emissions would be over 20 GtC/yr by 2100. Scenario B assumed far lower emissions ($\sim$10 GtC/yr) as a result of a shift to natural gas use and large efficiencies, afforestation and full phase out of CFCs. Scenario's C and D were better still, representing a shift towards renewables and nuclear in the late or early parts of the 21st century, respectively. Scenario D would see emissions at half their 1985 level by 2050 [1].

The IPCC Supplementary Report of 1992 [20] updated the scenarios. Their number was increased to six (a-f) and different and updated population, economic and technological assumptions were used for each one. Figure 2.7 shows the six CO_2 emissions scenarios until 2100, and similar ones were constructed for other greenhouse gases. Scenario IS92a is similar to the 1990 scenario A (SA90), and shows the result of existing climate policies together with medium economic growth (averaging 2.3%), medium population growth (11.3 billion by 2100) and medium energy resource availability (12,000 EJ and 13,000 EJ of oil and gas respectively). By 2100 the annual emission of CO_2 is equivalent to around 20 GtC. The lowest emissions growth occurs under IS92c, which assumed low resource availability and growth, and suggests carbon emissions of 4.8 GtC in 2100. The most severe case, IS92e, assumed high economic growth and resource availability, and implies carbon emissions of 36 GtC. For detailed information on the scenarios see Houghton *et al* [20].

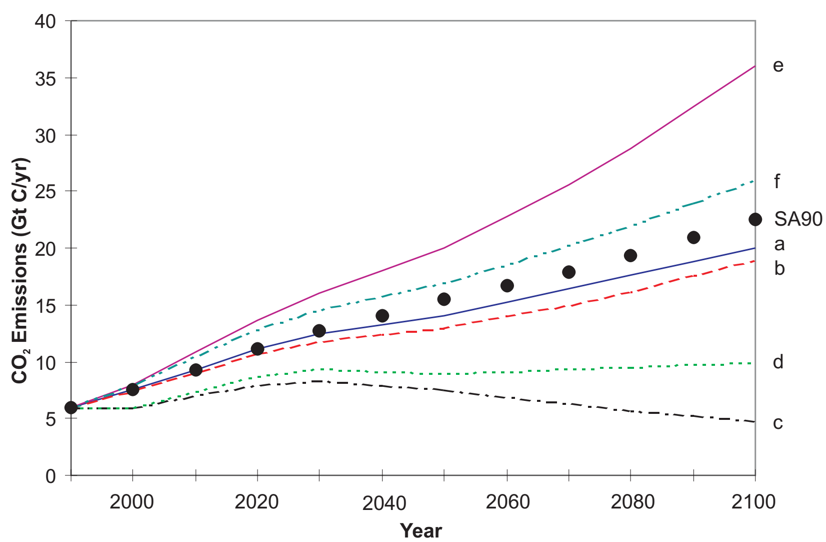


Figure 2.7: IPCC 1992 Emission Scenarios (a-f) and 1990 IPCC BaU [20]

The IPCC scenarios have recently been revised and are available in Nakicenovic and Swart [33].

Change in Radiative Forcing

To be able to determine the temperature changes that result from each scenario, there is a requirement to first find the radiative forcing due to the greenhouse gases.

The emissions scenarios are used to drive climate models to indicate the change in concentrations and radiative forcing. Greater emissions imply a higher realised concentration of gases, and hence the degree of forcing. The forcings that result from the IPCC 1992 scenarios follow the pattern of the emissions with the greatest forcing resulting from IS92e, the least from IS92c and the BaU (IS92a) lying in between. The change in forcing resulting from the 1992 scenarios are shown in Table 2.8. The effect of aerosols was considered for the SAR [29], and whilst they reduce overall radiative forcing, the overall pattern of forcing for each scenario is unchanged. The forcings can be seen to be larger than the change in forcing since pre-industrial times of 2.45 W/m^2 (from Section 2.1.5), and together with the IS92e case would imply a change in radiative forcing of around 9 W/m^2 over the period from pre-industrial times to 2100.

Scenario	IS92a	IS92b	IS92c	IS92d	IS92e	IS92f
$\Delta F (W/m^2)$	5.44	5.26	2.98	3.84	6.74	6.26

Table 2.8: Radiative forcing change over 1990-2100 for IPCC scenarios [27, 29]

Temperature Change

The degree of warming will depend on the sensitivity of the climate to increased forcing, and as the sensitivity is uncertain (along with the effect of aerosols) a range of warming scenarios tend to be presented. IPCC assessments have so far used simple upwelling-diffusion-energy balance models (UD/EB), rather than the more sophisticated global circulation models, to indicate the scale of temperature change. Although GCMs could be used to produce global mean temperature changes, this is not possible for a number of reasons. Firstly, each GCM has its own climate sensitivity and therefore cannot produce the desired range to take account of uncertainty in this variable. Also, the computing load required to carry out detailed studies of the numerous uncertainties is at present too great. However, by calibrating the simpler UD/EB models they can produce similar global mean results to GCMs [29].

For the IS92a scenario, the closest to a business-as-usual, we could expect a temperature rise of between 1.6°C and 3.5°C for low to high climate sensitivity. The inclusion of aerosol effects tends to reduce the temperature rise by around 0.5°C. For this scenario the realised temperature rise is expected to be around 2°C by 2100 [29].

Figure 2.8 shows the range of rises for a medium climate sensitivity, and indicates the relative certainty of a rise by 2050, but lesser certainty as the scenario paths diverge. For 2100, the range (including aerosols) is 1.3°C to 2.5°C for a medium climate sensitivity. The divergence is due to the long time lag between both emissions and concentration change and radiative forcing and eventual climate response. The extreme range of projections is from 0.8°C for scenario IS92c with a low climate sensitivity, to 4.5°C for scenario IS92e with a high climate sensitivity.

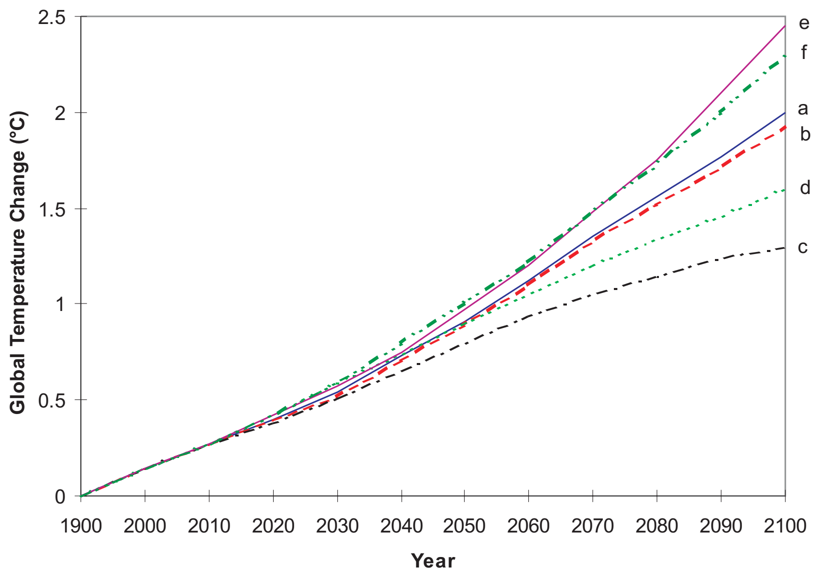


Figure 2.8: Temperature Rise from IPCC 1992 Scenarios for medium climate sensitivity [29]

It is notable that the estimates of temperature rise under a BaU scenario have fallen since 1990 and 1992, when the best guesses were 3.5°C and 2.5°C respectively [1, 20]. This due to a number of factors: differences in the emissions scenarios, improvements in the carbon cycle models used and the inclusion of aerosol effects [29].

Whilst the estimates presented here are for 2100, climate change is unlikely to halt then. In fact most of the curves in Figure 2.8 indicate rapid temperature rises in 2100, and it is likely that temperatures will continue to rise for some centuries, despite the stabilisation of greenhouse gas concentrations [34].

2.4 Potential Impacts

Of the large number of potential impacts resulting from climate change, there are a number of key areas where major impacts could be expected.

2.4.1 Sea Level Rise

On a geological time scale, the variation in sea level has been considerable, and is almost entirely related to changes in climate. Before the onset of the last ice age ($\sim$ 120,000 years ago) when the global temperature was slightly above the present, sea level was around 6 m higher, whilst at the maximum extent of the ice age ($\sim$ 18,000 years ago), sea level was around 100 m lower and the UK was connected to mainland Europe [3]. Over the last century, global mean sea level has risen 10-25 cm, and it is likely that this is due to the increase in global temperature. The factors possibly responsible are the thermal expansion of the oceans, and the melting of glaciers, ice caps and ice sheets. Changes in surface and ground water storage may also have affected sea level. The contribution of thermal expansion and glacier and ice cap melting to the rise are believed to be 2-7 cm and 2-5 cm, respectively. There is uncertainty as to whether the Antarctic or Greenland ice sheets have contributed to the rise. It is expected that mean sea level will rise by 50 cm by 2100 (with an uncertainty range of 20-86 cm), with most of the rise coming from thermal expansion [35].

2.4.2 Water Resources

Water is the most precious resource on the Earth despite 70% of the surface being covered in it. There are major variations in its availability, and ever increasing demands from rising populations and the desire for higher standards of living. Climate change will alter the availability of water: increased temperature implies greater evaporation, whilst precipitation levels will fall in many areas. The net effect is that in some areas less water will be available for agriculture, industry and domestic consumption. This will have serious impacts for many areas of water supply, and in particular for hydroelectric power provision. The impact on water supply and hydropower will be dealt with in detail in Chapter 4.

2.4.3 Agriculture and Food Supply

Once again the impacts are complex, and inter-related with social and economic change. Whilst crops can probably be matched fairly successfully with changing climates, plants and trees that take longer to mature may find themselves unsuited to the climate consequently suffering from stunted growth or increased vulnerability to pests [3]. Detailed studies of the effect of climate change on world food supply [36, 37] found that with appropriate adaptation, the effects would not be likely to impact on total food supply by a great deal. The negative effects would be partially compensated for by the effect of CO_2 fertilisation (where higher concentrations stimulate photosynthesis and hence plant growth). However, there would be an increased disparity between developed and developing nations, and cereal prices would be likely to increase, placing more of the population at risk of hunger.

2.4.4 Human Health

There are a number of direct and indirect impacts on human health. The most important is that climate change is likely to cause increased incidence of infectious and vector-borne diseases. The relationships between the environment and human health are extremely complex, and the effects will vary regionally. Mosquitoes are sensitive to changes in temperature and precipitation and tend take advantage of conditions favourable to them [38]. Higher temperatures could affect the incidence of malaria, dengue and yellow fever and types of encephalitis. Increases in winter temperatures may allow mosquitos to survive in temperate regions or higher altitudes, as cold temperatures often dictate survival. Transmission frequency may increase due to the effect of higher temperatures on mosquito and disease life cycles. Changes in precipitation may increase the availability of mosquito breeding grounds. The greatest impacts will be felt where malaria is introduced to areas where the population has no immunity.

Other factors may increase mortality and reduce quality of life: rising temperatures may lead to greater mortality through heat stress, although there will be partial compensation by a reduction in cold weather deaths; changing atmospheric composition and in particular increased low-level ozone, could well increase the incidence and severity of respiratory ailments. Changes in precipitation patterns may lead to longer and more severe drought and related starvation, increased flood incidence and increased storm intensity (*e.g.* tropical cyclones). A detailed consideration of health impacts and adaptation is given by McMichael [39].

2.4.5 Other Impacts

Overall, climate change impacts may cost annually between 1.5 and 2% of global gross national product (GNP). However, the level of impact and inherent cost will vary geographically and be very much dependent on economic development. Estimates for developed countries are similar to that for the United States at 1.1-1.5% per annum, whilst the developing world may suffer up to 9% losses. These figures are based on impacts on today's economies and generally do not take into account future demographic, economic or environmental trends, and extend to the middle of the 21st century only. Such studies do not include losses that cannot or are difficult to quantify in monetary terms, for example, loss of bio-diversity. Other impacts include environmental migration as people dispossessed by rising sea level or drought, migrate to avoid the effects. There could be as many as 150 million displaced by the year 2050 with major relocation cost as a result. The key feature of climate change impacts is that they appear to affect those in developing regions disproportionately, and such regions are less well placed to take adaptive or remedial measures. The political and social costs of an increasing poverty gap could be substantial [3].

2.5 Strategies for Dealing with Climate Change

This section explains how climate change is being tackled, potential problems with it, and how the problems could limit success.

2.5.1 Stabilising Emissions

Given the uncertainty surrounding climate change, there is an argument that suggests that the evidence is insufficiently strong to warrant taking action. Rather it would be better to research the issue and obtain precise information before taking suitable action. However, such an approach is dangerous, and incorrect. Many decisions have to be made in absence of certain information, often in a limited time frame, and decisions concerning climate change are no different.

The evidence summarised in the preceding sections of this chapter suggests that climate change is already underway and is likely to accelerate. The risks are large and taking action is the only option. The question is about how quickly we should act. The long time scales associated with carbon dioxide concentrations at first suggest that the speed of human response will not have an effect. In fact, the opposite is true.

Figure 2.9 shows a series of paths that CO_2 concentrations could follow on their way to stabilisation at a range of values higher than present, and the required emissions pathways to do this. By applying the wait and see approach, emissions keep on rising and so do concentrations, until action is taken. The action required at that stage to stabilise emissions is more drastic than that required by the approach that involves earlier action to reduce emissions.

2.5.2 Dealing with Climate Change

The United Nations Framework Convention on Climate Change (UNFCCC) was negotiated at the 'Earth Summit' in Rio de Janiero in 1992, and entered into force in 1994. The Parties to the Convention committed themselves to stabilising greenhouse gas concentrations 'at a level that would prevent dangerous anthropogenic interference with the climate system'. The main commitment of the Convention is

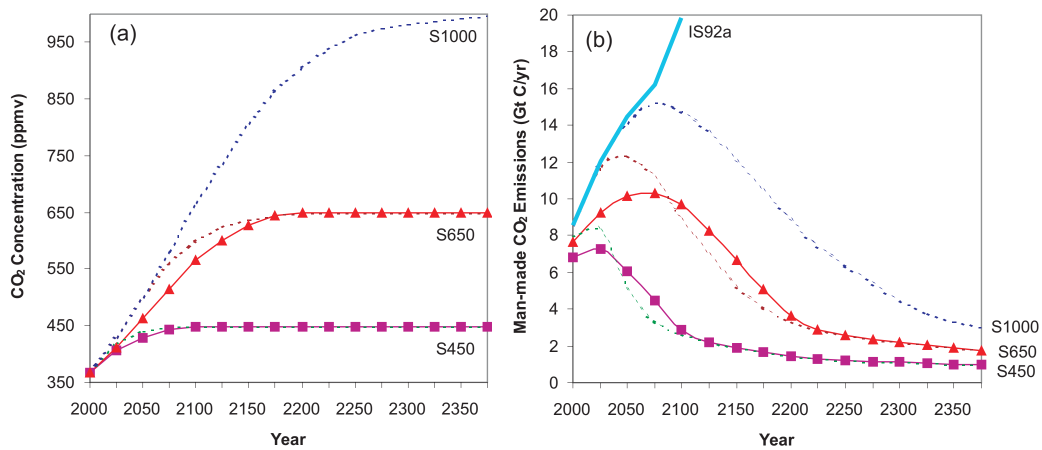


Figure 2.9: Stabilisation Pathways: (a) CO_2 concentration pathways leading to stabilisation. (b) emissions corresponding to (a) and IS92a scenario. Dashed lines allow emissions to follow IS92a in early 21st century [3]

for industrialised nations (referred to as Annex I countries) to return their emissions to 1990 levels, and to show declining emissions by 2000 [40]. Annual meetings of the Conference of Parties (COP) deal with issues relating to the Convention, and the sixth COP in the Hague November 2000 will continue to fill in the details of the more famous third meeting which delivered the Kyoto Protocol. The Protocol is examined in Section 2.5.3, but other milestones in the study of and action against climate change are listed in Table 2.9.

Time	Milestone
1957	International Geophysical Year
1972	Stockholm Conference
1985-87	UNEP/WMO Workshops
October 1988	IPCC Founded
November 1990	IPCC First Assessment Report
June 1992	UNFCCC Rio 'Earth' Summit
March/April 1995	Conference of the Parties (COP), Berlin
December 1995	IPCC Second Assessment Report
December 1997	3rd COP, Kyoto
November 2000	6th COP, Hague

Table 2.9: Milestones in climate study and strategy

2.5.3 Kyoto Protocol

The Kyoto Climate Treaty or Protocol has several key points [41, 42]:

- Binding commitments for greenhouse gases for each industrialised nation, defined for first commitment period of 2008-2012,
- Emissions based on 'basket' of six gases, plus allowances for sinks, land-use change and forestry,
- Collective commitment to reduce levels by 5% below 1990 levels,
- Removal of subsidies to energy use,
- Specific commitments to technology transfer,
- Joint Implementation,
- Tradable Emissions Permits.

The Protocol provides a collective commitment to reducing emissions by 5% below 1990 levels. Each industrialised nation, collectively known as Annex I countries, committed themselves to a specific reduction target for 2010, with developing nations not required to reduce theirs. Since 1990 the US, the EU and Japan have had roughly constant emissions, but have agreed to reductions of 7, 8 and 6% respectively [43]. In the UK's case, CO_2 emissions have fallen mainly as a result of the 'Dash for Gas' following the privatisation of the electricity industry, and the UK has gone further by committing itself to 12.5% by 2010 [44].

Following the collapse of the 'Iron Curtain' the economies of the former USSR have encountered virtual collapse. As a result, Russia and the Ukraine were emitting 30% less in 1996 than in 1990 [42]. Their flat emissions target at 1990 levels, gives them a large surplus of emissions that they can either absorb by rebuilding their economies or sell through the proposed market in emissions permits.

The six gases to be controlled are CO_2, CH_4, N_2O, HFCs, Perfluorocarbons (PFCs) and SF_6. The inclusion of gases allows their overall climate effect to be reduced at a lower cost than with carbon dioxide on its own. An example would be that for little cost or a small cost saving, leakage of methane from pipelines could be reduced and be a useful contribution to the overall reduction [3].

The 'Joint Implementation' (or 'Clean Development Mechanism') component of the treaty allows Annex I countries to provide investment in clean technology in a developing country and claim a 'credit' for the reduced emissions.

Developed as a mechanism for combating acid rain by reducing emissions [45], emissions permit trading is one of the provisions of the treaty. It is more efficient than traditional 'command and control' techniques and taxation. Each polluter, in this case a nation, is allocated or bids for permits to emit a given quantity of pollutant, in this case CO_2. The principle is that a polluter will fund abatement measures whilst the marginal cost of the measure is lower than the market price of the permits. If their cost is greater they will purchase from a vendor with lower abatement costs, and the trade in emission permits forms the least cost solution to the emissions problem. For information on the economics of tradable emissions permits refer to Chapman [42] or Tietenberg [46].

2.5.4 After the Protocol

The Kyoto Protocol has been signed by 84 countries to date. However, for it to come into force requires 55 Parties to ratify it, of which Fiji, Tuvalu and Trindad and Tobago are the only ones to do so. It is quite possible for the agreement to come into force without US ratification, but that step is regarded as crucial for its success [40]. At present there appears to be little likelihood of that as the partisan US Senate opposes it, unless Russia does so and shames the US into action.

Although the Kyoto treaty is a major global agreement, it will not have a major impact on limiting growth of emissions or atmospheric CO_2 concentrations. This is because it limits growth where growth is static, but does not place limits where emissions are growing rapidly (in developing nations). There are positive signs that developing nations will voluntarily commit themselves to emission limits (*e.g.* Argentina). One of the reasons for this is the attraction of joining the trading mechanism and earning hard currency, although selecting the appropriate target is a difficult task [40].

The Protocol is rather flexible, and there are a number of inherent dangers with its mechanisms. Firstly, whilst the large difference between actual and permitted emissions from Russia and the Ukraine could form the basis of trading of CO_2 permits by the US and other Annex I countries, it is a serious problem. The danger is that if Russia and the Ukraine sell a large portion of their excess the world price will be low and the US in particular will avoid having to reign in its emissions. The other extreme is where they supply so little that the price is too high and they lose much needed revenue. It may be difficult to strike a balance between Russia's need to increase its wealth and improve its economic and political stability, and limiting the ability of US and others to pollute. Secondly, the Clean Development Mechanism may allow Annex I countries to import a large portion of their reduction, and as a result they could actually increase their emissions rather than reduce them [40].

The level at which CO_2 concentrations are stabilised will depend partly on the speed of response from countries and the degree to which the developing world follows the lead of the Industrialised nations ('spillover'). To stabilise CO_2 emissions in the 450-550 ppmv range a number of things must occur [41]:

1. Kyoto should be in force (by around 2002) but with a degree of market flexibility,
2. Annex I nations need to demonstrate strong and credible domestic action,
3. United States must ratify by 2005 at the latest,
4. Open negotiations held in 2005 for the second period with more emission controls,
5. Strengthen technology development and international transfer to improve 'spillover'.

Despite the problems with it, the Kyoto Protocol is the benchmark for future agreement on 'substantive goals and economic incentives' [42]. If the Kyoto commitments can be achieved in the Industrialised nations then it places a moral obligation on the rest.

2.6 Summary

Atmospheric concentrations of CO_2 are rising faster than any period in recent history. The cause of the increase is anthropogenic emissions of carbon dioxide from deforestation and fossil fuel combustion. There is a correlation between concentration of greenhouse gases and global temperatures, supported by ice core data. The effect of continuing rises in greenhouse emissions will be temperature rise and altered climate.

Evidence suggests that climate change is underway. Global mean temperature has risen by around 0.6°C since pre-industrial times. 1998 was the warmest year and the 1990s were the warmest decade on record and of the last millennium.

The most promising method of indicating future temperature rise and other climatic changes is the use of General Circulation Models, although they are limited in their application by incomplete understanding of physical processes, in particular of feedbacks from clouds, and computer power. Despite this they are reproducing the broad pattern of current climate reasonably well, with some variables better correlated than others, but regional patterns are not well represented.

Projections of future climate are based on scenarios of greenhouse gas emissions. Between 1990 and 2100 temperature is expected to rise by around 2°C. Precipitation change is more uncertain, but an increase in global mean of up to 15% is expected.

The impacts of climatic change will be many and varied. Effects on sea level, agriculture and food supply, human health, ecosystems, and water resources are forecast. The economic impact is expected to be around 1.5% of global gross world product, with developing nations more badly affected.

The UN Framework Convention on Climate Change was created to form the basis for global action on climate change. The preferred method is to limit emissions of greenhouse gases. The sooner this occurs the less of an impact it will have on the global economy.

The Kyoto Protocol is a key agreement that commits industrialised nations to limiting emissions, and whilst the agreement itself is limited, it will form the basis for future emissions cuts.

Chapter 3

Electricity Supply and Change

In addition to familiarity with the issues surrounding climate change, it is essential to understand how the future development of the electricity supply industry (ESI) will impact on climate change. This chapter summarises the environmental impact of emissions from fossil-fuelled power stations, and indicates measures for their mitigation, in particular the emissions of carbon dioxide. The relationship between economic development and electricity generation is examined, together with their effect on future greenhouse gas emissions. A brief history of the ESI sets the scene for the discussion of deregulation and liberalisation of the industry. The trends and impacts are explored with particular reference to the role of renewable energy sources.

3.1 Environmental Impacts of Electricity Generation

The vast majority of the World's electricity is produced from the burning of fossil fuels, which have been shown to be the major cause of increasing atmospheric concentrations of greenhouse gases. Other impacts include acid rain, radioactivity and particulates.

3.1.1 Greenhouse Gas Emissions

In 1997 UK emissions of CO_2 totalled 155 Mt of carbon equivalent (MtC). Table 3.1 shows that 26% of carbon emissions were from power stations, down from 32% in 1990. Despite the fact that the biggest growth has been seen in emissions from road transport, it is the energy sector and electricity in particular that are considered here.

The UK is responsible for 2.5% of global CO_2 emissions, with 92% of emissions due to

Sector	MtC	%
Power stations	40	26
Domestic	23	15
Commercial and public service	9	6
Industrial combustion	39	25
Land use change and forestry	8	5
Road transport	32	20
Other transport	2	1
Others	3	2
Total	155	100

Table 3.1: UK CO_2 emissions by sector for 1997 [47]

energy consumption. There was a decrease of 8% (13 Mt C) between 1990 and 1997, with emissions from power stations falling by 14 Mt C. Since 1970, CO_2 emissions from power stations have fallen by 29%, electricity generation has increased by 44% whilst the emissions per unit have declined by 43%. The fuel type strongly influences the emission of carbon dioxide. On average, coal creates 25 kg of carbon per GJ, and oil and gas releasing 19 kg and 14 kg respectively [47]. Nuclear and renewable sources release little or no CO_2. These differences along with improved efficiencies account for the fall in carbon dioxide emissions from UK power stations.

In addition to CO_2, fossil fuels release other greenhouse gases, including methane. Direct emissions as a result of combustion in power stations are responsible for around 1% of the UK methane emissions. However, 28% of the total is caused by coal, oil and gas extraction, and as electricity generation uses these fuels, it accounts for a significant fraction of the indirect emissions. Other greenhouse gases emitted include carbon monoxide, SO_2, and nitrogen oxides.

Methods for the mitigation of carbon dioxide emissions from fossil-fuelled power stations are discussed in Section 3.2.

3.1.2 Acid Rain

Sulphur dioxide is created by the combustion of sulphur-containing fuels, like coal and oil. Once in the atmosphere it forms aerosol particles that create a cooling effect. Whilst this tends to offset the warming from greenhouse gases, these particles do not remain in the atmosphere for long and are precipitated over a wide area downwind of their source. The SO_2 is deposited as sulphuric acid and there is a great deal of evidence that 'Acid Rain' damages plants, lakes and ecosystems, with the UK causing damage as far afield as Scandinavia.

In 1970 around 6.5 Mt of SO_2 was emitted in the UK, of which 45% was from from power stations. Legislation, including the 1988 European Commission (EC) Large Combustion Plant Directive has imposed limits on emissions. The UK is required to lower emissions to 60% of 1980 levels by 2003 [48]. By 1997, UK emissions had fallen to 1.7 Mt, with the majority (62%) of remaining pollutant attributed to power generation. The emissions from power stations were slowly declining up to 1990, but have since seen a marked decline [47], due to lower coal use and the use of sulphur removal technologies.

Methods of sulphur removal include treating coal before ignition, combustion processes that collect sulphur in the ash, and removing SO_2 from the combustion gases before entry into the atmosphere, known as Flue Gas Desulphurisation (FGD). Although effective, FGD is expensive and reduces station efficiency [48].

The oxides of nitrogen, or NO_x, also contribute to acid rain. The major source of NO_x in the UK is road transport, but power stations account for around one-fifth. Emissions can be reduced by introducing alkalis to the flue gas, and whilst such practices are carried out elsewhere, no scrubbing methods have been applied in the UK [49]. The overall level of UK emissions is now around half that for 1970. Once again a marked decline since 1990 is attributed to greater usage of gas plant, and the retro-fitting of low NO_x burners to existing coal-fired stations [47].

3.1.3 Radiation

Nuclear power is subject to public concern about its safety and in particular about releases of ionising radiation into the environment, from the use, reprocessing and storage of nuclear fuel. While much of this fear stems from catastrophic releases due to reactor faults or failures, such as the 1987 Chernobyl disaster, others are concerned about releases from contaminated reactor coolant or discharges during reprocessing. The long term problem for nuclear power is how to store the waste fuel and contaminated equipment as well as how best to decommission the stations in a cost-effective manner. Table 3.2 indicates that fossil-fuelled plant also emit radioactive particles, mainly as a result of trace elements in the fuel. Public exposure to these radioactive particles is similar to that from nuclear stations [49].

The radiation dosage received by the public is due mainly to cosmic radiation (85%), whilst nuclear and coal fired stations are responsible for 0.01% and 0.004% respectively, and so do not contribute significantly to public exposure. Even close to a nuclear installation local residents are deemed unlikely to receive doses more than 1% above natural radiation levels [49].

The effects of radiation exposure include increased probability of cancer, and very large doses can lead to radiation sickness and death, although the risk is dose dependent. Whilst the average lifetime risk of cancer is increased by 0.1%, the hereditary impact has not been ruled out. One of the most heavily reported effects of nuclear installations is the apparently high incidence of leukaemia in populations nearby, although the rarity of the disease makes statistical treatment difficult. Some findings indicate that exposure of the father to radiation in the period around the child's conception increased the risk of the disease of 6 to 8 times [49].

3.1.4 Other Pollutants

Carbon monoxide emissions resulting from incomplete combustion are dominated by road transport, with power generation creating around 1%. Particulates, linked with respiratory ailments are also emitted from power stations (in particular coal) which contribute 6-12%. The incidence of both types of atmospheric pollution is decreasing [47]. Coal stations create large quantities of ash which must be disposed of either in landfill or reclamation schemes; a typical 2,000 MW coal station will produce 840,000 tonnes of ash per year [49]. A summary of the emissions from typical fossil-fuelled plant is given in Table 3.2.

3.2 Mitigation of Carbon Emissions

There are a wide range of technological and policy options available to counter the carbon problem, and they can be broadly classified as:

- Fuel switching,
- Increased use of renewable energy,
- Increased use of nuclear energy,
- Increased generation, transmission and end use efficiencies,
- Decarbonisation and CO_2 sequestration.

3.2.1 Fuel Switching

Altering the fuel type in favour of lower or zero carbon fuels is the key method of reducing CO_2 emissions. Natural gas which is predominantly methane, produces 40% less carbon dioxide per unit mass consumed than coal, and oil creates 20% less. Other benefits accrue from switching to natural gas, as Table 3.2, which summarises the key pollutants from fossil-fuelled plant, indicates. It can be seen that coal is the worst polluter in terms of gaseous and solid emissions. Switching to natural gas from coal and oil lowers CO_2 emissions by 45% and 33% respectively, reduces NO_x, and eliminates SO_2, solid waste and particulates.

The use of combined cycle gas turbine (CCGT) stations raises the conversion efficiency from a typical 30% to around 45-50%, further lowering the unit emissions.

Pollutant	Coal	Oil	CCGT
Carbon dioxide	5,500,000	4,500,000	3,000,000
Sulphur dioxide	75,000	85,000	~0
Nitrogen oxides	22,500	16,000	5,000
Particulates	3,500	1,500	~0
Solids	420,000	~0	~0
Ionising radiation (Bq)	10^{11}	10^{9}	10^{12}

Table 3.2: Typical emissions from 1000 MW Fossil Fuel Stations, in t/yr [50]

Whilst switching to a lower carbon fuel like natural gas will produce less CO_2, the increased demand for methane would result in increased pipeline and processing leakage. The greater global warming potential of methane means that this would tend to partially offset the benefit of lower carbon emissions [50]. Despite this, the environmental benefits of fuel switching are clear.

3.2.2 Renewables

Renewable energy currently supplies around 20% of world primary energy, with hydropower and biomass dominant [51]. As Table 3.3 indicates, the potential contribution of renewables is great, and could supply current primary energy needs, with policies that encourage their usage. The long-term technical potential is large enough to meet energy needs in the future. All are driven by the Sun's energy, so as long as it is still shining, they should be available. The advantages of renewable sources are that unlike fossil fuels they are infinite (over time), and that they have low (if any) greenhouse gas emissions, although they do require finite resources to be used to harness them (*e.g.* land, copper, *etc.*).

Hydropower

Hydropower is the largest renewable energy source and contributes 2,200 TWh annually, or around 18% of world electricity generation [52]. The energy source tapped is the gravitational potential of falling water, as it makes it way back to the oceans after being evaporated and precipitated onto the land. The technical potential is around 14,000 TWh annually [53], but the economically exploitable potential is

	Consumption		Potential	
	1860-1990	1990	$\sim$ 2025	Technical
Hydro	560	21	35-55	> 130
Wind	-	-	7-10	> 130
Geothermal	-	< 1	4	> 20
Solar	-	-	16-22	$> 2,600$
Biomass	1,150	55	72-137	$> 1,300$
Total	1,710	77	130-230	$> 4,200$

Table 3.3: World renewable energy potentials by 2025, EJ [51]

between 40 and 65% of that, and much of the more economic plant has already been built. The contribution varies between nations with some like Norway deriving 99% of their electricity from it [54], and others little or none.

Although hydro is a versatile source of power, it is not free of environmental impacts. The flooding of vegetation by the reservoir produces methane and other greenhouse gases as the vegetation decays, and in some tropical sites the emissions can be similar to those from fossil fuel stations during this time [55]. Negative impacts include removal of agricultural land, relocation of populations, and effects on ecosystems [56]. A positive impact is that the infrastructure required to construct a large dam tends to stimulate regional economies [57]. A fuller discussion of the potential and problems with hydropower is to be found in Chapter 4.

Biomass

Currently, large amounts of energy from biomass are consumed, mainly for cooking and heating in developing countries. It is carbon neutral, *i.e.* there is no net increase in atmospheric CO_2, as any released during combustion is balanced by that taken up during growth. The real potential is in the use of 'modern' biomass to create usable energy and in particular electricity. Sources include municipal waste, industrial or agricultural residues, forests and energy plantations. Biomass could be used to generate electricity for rural villages or to fire large power stations, where similar technologies to coal could be used. Negative aspects include the need to remove hazardous contaminants from municipal waste [52].

Wind

Harnessing the wind is an age old activity, and modern wind turbine technology is mature. Sited alone or grouped in 'farms', most turbines are rated up to 1 MW. Current farms are on-shore but greater output can be gained siting them offshore, as the potential is greater. The UK is well suited to producing wind energy and could generate up to 30 TWh from on-shore sites by 2025, but the technical and financial difficulties of offshore facilities is likely to limit their supply to a fraction of the potential 140 TWh [49].

UK capacity is presently around 360 MW, but other European countries are investing heavily, in particular Denmark which is aiming at generating around half its electricity from wind by 2030 [58]. In Europe as a whole, current capacity is 8,500 MW [59], and the target for 2020 is 100 GW [60].

The intermittent nature of wind energy implies that on a large grid system, the acceptable contribution of wind is around 15-20%, in order to avoid compromising system security [52]. However, the provision of significant levels of storage would allow wind to supply base load.

The negative impacts of the turbines include visual intrusiveness, aerodynamic and mechanical noise, interference with communication and TV, and in some cases the export from the wind farm may lead to local voltage violations in supply quality in the distribution network. These problems have led to refusal of planning permission and have seriously limited the growth of wind energy in the UK, when compared with other European counties.

Solar

The Sun's energy can be harnessed directly through photo-voltaic (PV) cells or solar-thermal systems. PV cells convert sunlight directly into electricity, with an efficiency of around 15-20%, but they are currently too expensive to compete with fossil fuels. Solar-thermal systems concentrate the Sun's rays onto a collector that heats a working fluid, and drives a turbine to create electricity. They are best located in areas of high sunlight intensity, and as such California has an installed capacity of 350 MW of co-fired solar collector plants. More development will be required before such plant can replace fossil fuels [52].

Other Sources

Geothermal energy uses heat stored in the Earth's crust to generate power. The technology and practice of pumping hot water from underground has been around since the 1960s, and current installed capacity is 6 GW. The use of 'hot dry rock' technology is still experimental and involves passing cold water down a deep shaft and extracting hot water from one nearby to drive a steam turbine. The UK is estimated to have a technical potential of 210 TWh annually, although only a small proportion is likely to be exploited [49]. Globally, around 2% of energy requirements are likely to be met with the technology [52].

The oceans could provide large amounts of energy by harnessing the tides, waves, and thermal and saline gradients. Tidal barrages could generate a significant proportion of energy especially in the UK. The proposed Severn Barrage could have an installed capacity of 7.2 GW [61], although the output would be cyclical and would have to be supplemented by other stations. The required civil engineering works would be costly and this is reflected in the cost of the energy. Developments on this scale would require significant input from Governments. Often the better sites are ones of environmental beauty [52], although in some cases, like the Mersey barrage, the environment may be improved. Shore-based wave energy stations exist but are small-scale and have limited potential. Greater scope lies in offshore devices but their developers must overcome significant engineering and cost problems before they can be implemented.

Problems with Renewables

The intermittent nature of many renewable sources is a problem, whether it is the short term variations in wind output or the cycles associated with tidal or solar. On occasion the rising output coincides with high demand, but this cannot be guaranteed, and reasonably accurate predictions may only be available a few hours in advance.

Most sources are remote from the high voltage transmission grid system, and must be 'embedded' in distribution systems, which were not designed to export power to the grid. This can create difficulties in maintaining voltage within statutory limits, and the operator may insist on a line upgrade, adding to the capital cost. This is one of the reasons why many renewables projects consented in the UK under the Non-Fossil Fuel Obligations and others were never pursued.

Many renewable technologies are relatively new or unproven, and as a result have not had the benefit of commercial development. Many are in hazardous environments, and require technology that is currently expensive to ensure their successful application. With continued development, many of the difficulties should be overcome. Technologies, such as wind, that can be batch produced may deliver significant cost efficiencies, however, many site specific technologies (*e.g.* hydropower) will still bear the costs of heterogeneity.

Although most renewable sources have no fuel costs, and low variable operations and maintenance (O&M), the capital outlay can be considerable, especially where substantial civil works are required (*e.g.* tidal and hydropower). This puts them at a disadvantage in terms of investment risk, as the debt repayment is longer. Experience with wind power suggests that the unit cost of renewables falls over time, and implies that most technologies are likely to approach current production costs of fossil fuels within the next few decades. If fossil fuel prices increase as a result of supply and demand changes, or fiscal measures to limit greenhouse gas emissions, then many forms of renewable energy will become competitive.

3.2.3 Nuclear Energy

Current nuclear technology requires fissionable materials such as uranium to raise stream and drive turbines. The fuels are available in sufficient quantities as not to pose a problem for expansion, although uranium alone could not be relied upon.

In common with hydropower, the capital costs of nuclear power are high, whilst the fuel cycle costs are relatively low. Storage in a repository is expected to add around 20% to the total lifetime cost, whilst discounting reduces the percentage further. Current costs are in the region of $25-60 per MWh [52].

Proliferation of nuclear materials for use in weapons is a serious concern. A 1000 MW light water reactor produces around 200 kg of plutonium each year, and a bomb with the same power as that dropped on Nagasaki could be produced with 4-10 kg. In theory any separated plutonium can be used for bomb-making although the use of reactor-grade material complicates the exercise.

Although runaway in reactors is not likely with correct maintenance and operation, some designs are inherently more safe. The use of gas cooled reactors with graphite moderators, and more passive safety features are ways of achieving safer operation. Removing plutonium or reducing its quantity in waste is perhaps the best way of reducing the proliferation risk. Thorium could provide the fuel for an 'Energy Amplifier' driven by a proton accelerator, and would be sub-critical and assist in the reduction of waste [62].

Long term, nuclear fusion is the key technology, and would provide a virtually unlimited supply of energy.

3.2.4 Improving Efficiency

Efficiency gains are a key approach in reducing carbon emissions. The overall efficiency of an energy system depends on the individual process efficiencies, the structure of supply and conversion, and end-use patterns. While losses in one particular component of the generation-consumer chain may be relatively small, when considered as a whole, the losses can be considerable. Overall energy-use efficiencies worldwide are estimated to be between 15 and 30% [51]. Estimates suggest that a 1% increase in the efficiency of power generation will result in a 2.5% fall in CO_2

emissions. Therefore, measures to improve the efficiency of generation, transmission and end-use of electricity could yield significant savings in emissions.

Generation

Thermal stations, including nuclear are fundamentally limited by their Carnot efficiency. Two thermodynamic cycles are used for power generation: the Rankine cycle for steam turbines and the Joule cycle for gas turbines, and typical efficiencies are around 35-40% [63]. The steam cycle uses fuel to raise steam in a boiler and creates power by allowing it to expand in a turbine, and it is used in traditional coal, oil and nuclear plant. The gas cycle compresses air, mixes it with gaseous fuel, ignites it and again allows the hot gas to expand through the turbine. The efficiency of the gas turbine cycle is determined by the pressure ratios of the turbine and compressor, and the temperature. The maximum cycle temperature is limited by the material limitations of the turbine blades, which are under great mechanical stress. Modifications to both cycles (*e.g.* steam super-heating and multiple turbine stages) can improve efficiency, but incurs increased complexity and capital cost.

By combining the two cycle types additional efficiencies can be achieved. Combined cycle gas turbine plants are currently achieving efficiencies of over 46%, with an expectation of 52-55% within a few years [52], and use the hot exhaust gases from a gas turbine to raise steam and drive a steam turbine. All new gas plant in the UK has been CCGT, and this has been due to a number of factors: low capital cost, short installation periods and the potential for operating flexibility.

The efficiency of coal plant can be improved with so-called 'clean coal' technologies. Pressurised fluidised bed combustion features air blown upwards through a bed of hot sand and ash, which allows more efficient ignition of coal fed into the bed. Emissions of SO_2 can be reduced if limestone is added to the bed and reacted. This works even for high-sulphur fuels and could be suitable for parts of the Third World [49]. Increased efficiency and reduced emissions result from the 'gasification' of coal, its scrubbing and use in a gas turbine. The extension of this, the Integrated Gasification Combined Cycle (IGCC) operates in a similar way to CCGT plant, and could achieve efficiencies of 42-46% [51].

Transmission

Losses in electricity transmission systems, which are typically around 2-5%, tend to amplify the effect of changes in demand. If, for example, losses are 3% then a 100 MW increase in demand requires an increase in generation output of 103 MW, and an increase in fuel consumption and emissions. High voltage grids are designed to allow efficient use of all generation sources, and secure, reliable electricity supplies.

If the generation and loads are geographically balanced then the transmission losses are close to zero. However, if generation is predominantly and increasingly located away from the load centres and closer to the fuel source, then losses will increase. This is the case in the UK, with generation in the North and load in the South creating large flows of active and reactive power. Careful siting of plant assists with containing losses, as can the use of higher operating voltages, the use of high voltage DC on long transmission lines, and the use of reactive power compensation (*e.g.* static VAr compensation) which reduces reactive power flows [64].

Use

Domestic energy use in the UK now represents 29% of the total, second only to transport. The pattern of domestic energy use has changed considerably over the past 30 years. While overall energy use had increased by 22%, electricity use has increased at around twice the rate, due mainly to the increase in domestic appliances. In 1998, cold storage appliances and lighting together accounted for around 47% of domestic demand. While the efficiency of lighting has improved, the switch to more efficient fluorescent bulbs has been slow and there has been a tendency towards multiple light source lighting. The scope for electricity savings from efficient appliances is considerable, but will be hampered by the low proportion of household income spent on energy. Industry takes around a quarter of its energy in the form of electricity, and this proportion has been grown steadily with usage increasing by 31% since 1970. The service sector takes around a third as electricity, and the transport sector less than 1%, mainly for rail transport [47].

Overall, there is a great deal of scope for electrical efficiency gains, from better design and more considerate usage.

3.2.5 Carbon Removal, Storage and Sequestration

The long term goal of energy supply is to move away from a carbon economy towards one using hydrogen, either by using it as a combustible fuel or through nuclear fusion. Until then, if the climate impacts of fossil fuels are to be contained, then a means of capturing and storing CO_2 must be implemented. As power stations are large and stationary CO_2 point sources, then the available technologies must be applied to them first.

Decarbonisation

Decarbonisation removes the primary objection to the use of fossil fuels, and would allow their continued use, and effectively allow the use of the energy contained in carbon fuels with lower emissions of CO_2. Two approaches are possible: fuel decarbonisation or flue gas decarbonisation. Both require that the CO_2 removed is prevented from reaching the atmosphere either by use or storage.

Removal of CO_2 from the flue gases incurs direct financial costs of operating the removal process, as well as lost energy through a lowering of overall station efficiency. The efficiency loss could be up to 10 percentage points, depending on the proportion of the carbon being removed, the fuel, and the scheme. Several schemes have been proposed including amine or sea water absorption, molecular sieves and the use of refrigeration [65]. The use of a flue capture scheme of these varieties is expected to increase electricity prices by 50-80%, equivalent to $150-210 per tonne of carbon avoided. Another scheme being investigated using oxygen rather than air for combustion, would make removal easier as the flue gas would be virtually pure CO_2. This scheme is estimated to cost around $80 per tonne of carbon avoided [66].

Fuel decarbonisation requires the conversion of the fossil fuel into CO_2 and hydrogen, which are then separated. The H_2 rich fuel is then used in combined cycle plant, releasing around one-sixth of the CO_2 compared to the fossil fuel. The efficiency drops are expected to be around 6 percentage points, raising the electricity price by around 30-40%, equivalent to $80 per tonne of carbon removed [66]. Greater efficiencies could be achieved with the use of fuel cells [67].

Storage

For any decarbonisation scheme to succeed, the CO_2 must be stored securely and isolated from the atmosphere. Table 3.4 indicates conservative estimates of the potential for several storage options.

Scheme	Capacity
Enhanced Oil Recovery	> 20
Exhausted Gas Wells	> 90
Exhausted Oil Wells	> 40
Saline Aquifers	> 90
Ocean Disposal	$> 1,200$

Table 3.4: Global CO_2 Storage Potentials, in GtC [52]

CO_2 is already used in the United States for enhanced oil recovery (EOR), which uses the pressurised CO_2 to force increased quantities of oil from the well. At current oil prices, only natural sources of CO_2 are economically viable, and these are tapped and piped [52].

Storage in exhausted oil and gas wells is a good option, as the carbon storage capacity of the fields is believed to be twice that contained in the original gas. Depending on the quantity of recoverable oil and gas the potential storage capacity ranges from 130 to 500 GtC. Storage in on-shore gas fields is expected to cost less than $11 per tonne [66].

The oceans are the greatest potential carbon storage scheme. They currently store 38,000 GtC, and will eventually absorb a high proportion of the anthropogenic CO_2 released into the atmosphere [1]. Even though some of the CO_2 pumped directly into the deep ocean will reach the atmosphere, it estimated that this will take several centuries. Disposal at a depth of one kilometre is viable, although the greatest cost will be transportation. Large releases of carbon direct into the ocean are likely to have environmental effects, particularly on marine life. These effects are expected to be localised around the release site, and would represent a negligible fraction of the total ocean. Increased CO_2 concentrations will acidify the oceans, and the expectation is that around 1,200 GtC would raise the pH level by around 0.2 [52].

Sequestration

The major means of sequestrating CO_2 is to allow vegetation to remove it from the atmosphere. Deliberate reforestation could go some way to offsetting emissions. Estimates of the cost per tonne of carbon stored as forest growth range from $3.50 to $30, and with high levels of reforestation costs would increase [68]. The land requirement is huge, requiring an area of 1,700 km^2 to offset the emissions from a 500 MW coal station [52].

One scheme under consideration is based on the development of a methanol economy, prior to or instead of a hydrogen based one [69]. Methanol is easier to handle being liquid at room temperature and could use existing petroleum infrastructure. The scheme uses hydrogen produced from electrolysis, to convert CO_2 from power station flues into methanol. The system would allow the energy to be released from fossil stations, use renewable or nuclear energy for electrolysis, as well as creating a source of methanol, which would allow the emissions problems of road vehicles to be addressed.

3.3 Development and Electricity Demand

The electricity sector contributes £11 billion to the UK's economy, which is around 1.3% of GDP, and just over a third of the total contribution from the energy industry. In recent years, the average annual increase has been around 10% [47]. The share of atmospheric pollution attributed to electricity generation appears out of proportion with its contribution to national wealth, implying that it is overly polluting for the benefit that is derived [70]. That, however, neglects the indirect economic and social benefits created by electricity availability and use.

Electricity availability is one of the key determinants of wealth creation, as shown by a recent study of the G7 countries [70]. It concluded that electricity use, rather than energy use as a whole, was significantly correlated to wealth creation, and that the share of final energy consumed in the form of electricity tends to increase with development. In the UK, the proportion of energy used in the form of electricity doubled between 1962 and 1990 [47]. Energy use is also correlated with higher life expectancy, and lower infant mortality or illiteracy [53].

Although capital intensive, the electricity supply industry is a major employer. In the UK it employs around 66,000 people, and although this is a far cry from the 150,000 employed in 1980, the ESI is now the major employer in the energy industry. It has replaced coal mining, which employed 297,000 in 1980, now around 5,000. The fall in employment in the ESI is due to greater 'efficiencies' following privatisation.

Modern society relies heavily on electricity. It is required for lighting, motive power, water supply, communications and information technology, medical care, and improving quality of life.

Inaccessibility to energy is a major cause of poverty, hardship and a contributory factor in rural-urban migration which causes urban stresses [53]. More than a billion people have no energy source other than simple fuel-wood, and a further two billion have supplies that can barely meet their basic needs. Energy demand is increasing rapidly in the developing world, at a rate similar to economic growth. In 1990, developing countries (DCs), accounting for 75% of World population, consumed around 33% of total energy. In 2020, the same countries will account for 85% of population and 55% of energy use [53], with world energy demand expected to be 65% higher than in 1990 [71]. Limitations in energy supply will constrain their social and economic development [72].

3.3.1 Future Demand

The primary driving forces of energy demand are population, the requirement to satisfy basic needs, the need for services that energy provides, and material expectations and desires. The strong correlation between economic growth and electricity demand implies that as electricity use is a proxy for economic development, electricity demand will rise faster than overall energy demand. It is therefore particularly important to project future electricity demand. However, the complexity of the relationships between development, economic growth and electricity use and availability make this very difficult.

In the short term, it is normally relatively straight forward for utilities to project likely electricity demand, with the expectation that the trends of the last few years will continue. Over the medium term it becomes more difficult, particularly in liberalised industries, and assumptions of future economic and political conditions must be taken into account. In the UK, the National Grid Company publishes its best guess of likely demand and investment opportunities for up to seven years ahead in its Seven Year Statement [73]. It expects UK electricity demand to grow by approximately 1.5% a year, to around 327 TWh in 2004/5, with peak demand growing at the same rate to around 56 GW.

Over the long term and beyond, more sophisticated methods must be used. In a similar manner to the IPCC emissions scenarios, the World Energy Council (WEC) defined several scenarios of energy demand up to 2020 in their 1993 report 'Energy for Tomorrow's World' [53]. Further work [74] with the International Institute for Applied Systems Analysis (IIASA) has extended the scope of the study to the end of the 21st century. An increased number of scenarios (shown in Table 3.5) considered different cases of resource availability and energy policy. Complex and interlinked models of demographics, economics, engineering and climate were used to project energy demand and supply into the future.

Scenario	Definition
B	Middle Course
A1	High growth, ample oil and gas
A2	High growth, return to coal
A3	High growth, fossil phase out
C1	Ecologically driven, new renewables with nuclear phase out
C2	Ecologically driven, renewables and new nuclear

Table 3.5: IIASA/WEC Global Energy Scenario Definitions [74]

All scenarios show considerable growth in annual electricity demand, up from around 12,000 TWh in 1990 to between 16,200 and 18,500 TWh in 2020, in line with the expectations of the International Energy Agency (IEA) [71]. By the end of the 21st century the scenarios indicate electricity demand levels of 3.6 to 8.3 times the 1990 levels. Figure 3.1 shows the demand growth for 4 of the six scenarios. The greatest demand levels occur with high growth and adequate oil and gas to sustain the large increase. The ecologically driven scenario C1 shows growth around half that of the high growth scenarios, particularly after 2050.

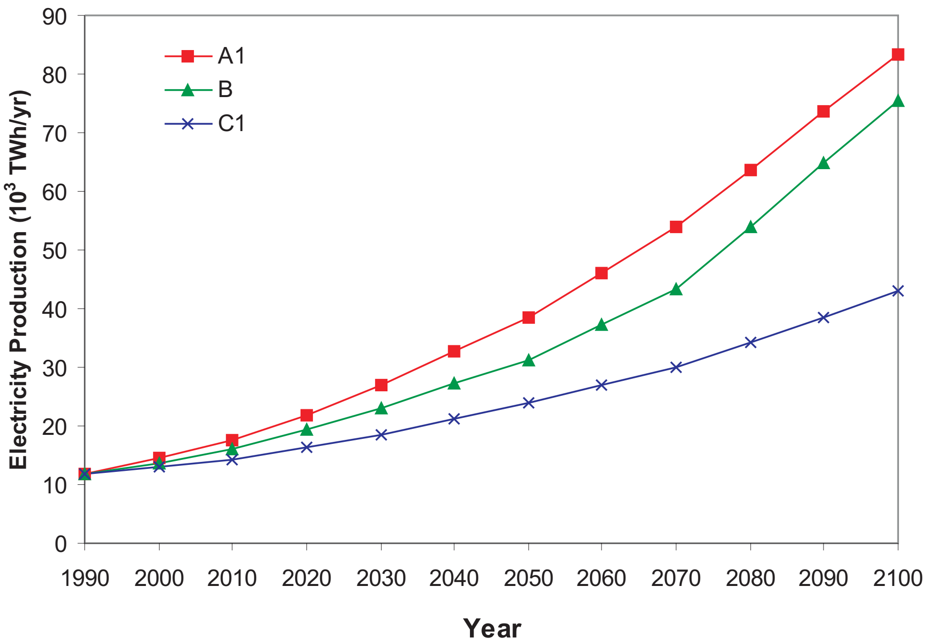


Figure 3.1: IIASA/WEC Electricity Supply Scenarios to 2100, in TWh [74]

3.3.2 Fuel Type

Of more note is the difference in future fuel sources between the scenarios. In 1990, electricity supply was dominated by coal which accounted for 38% of the global total. Hydropower and nuclear took 18% and 17% respectively, and gas and oil were responsible for 14% and 10%. The balance was supplied by renewables [74]. Each technology's future share will depend on environmental policy and legislation, fuel security, and availability, but most importantly on the relative costs of the supply method. To illustrate the effects of these factors, the future supply sources for WEC/IIASA scenarios A1, B and C1 are shown in Figures 3.2 to 3.4.

Scenario B sees coal remain the primary fuel until around 2040. Its share increases until 2010, before declining steadily to 8% in 2100. The peak usage occurs between 2020-2030, and lies 30% above its 1990 level in 2100. Oil use declines to less than 10% of the 1990 level. Nuclear use increases by over 17 times and supplies nearly half of the electricity in 2100. Hydropower's share falls from 18% to just under 10% whilst the energy supplied increases threefold. The energy supplied by newer technologies (solar, biomass, *etc.*) will represent 30% in 2100, an increase of 71 times! Overall the energy increase is some 6 times.

The high growth scenario (A1) sees a major expansion in natural gas use, particularly in the second half of the century, as ample supplies keep the prices down. By 2100,

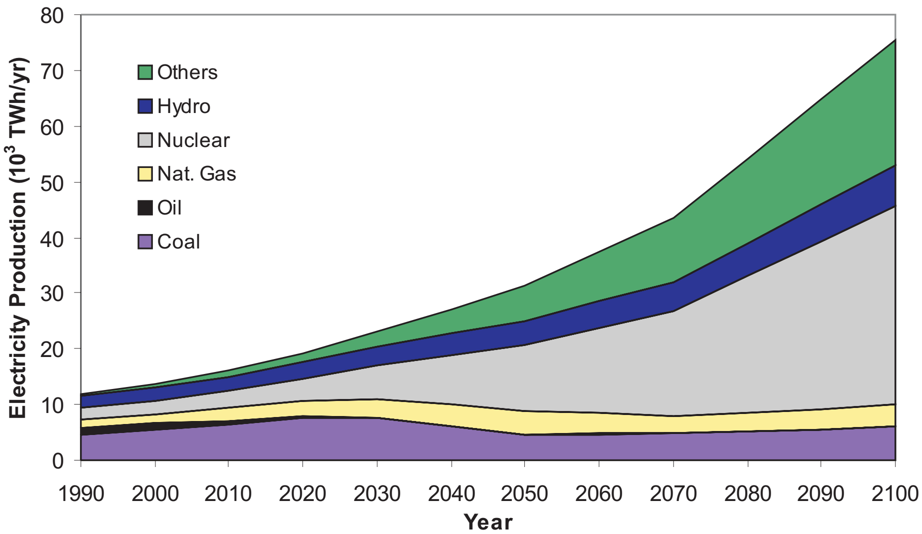


Figure 3.2: Middle course WEC/IIASA electricity supply scenario B [74]

gas use will have risen by 14 times. Coal use is projected to be lower than scenario B, and its final contribution is around 40% of 1990 levels. Nuclear, gas and the renewable sources will each account for around 30% of supply, with the balance being mainly hydropower.

The ecologically-driven scenario (C1) sees hydropower maintain its percentage share and increase production by 3.6 times. Oil use is virtually eliminated by 2050, whilst coal and nuclear decline and all but disappear by 2060. Natural gas use increases five-fold, with it share peaking in 2050 and falling to 21% by 2100. The balance of supply comes from renewable resources which increase by 4 times by 2020, 30 times by 2050 and 80 times by 2100. Its share at the end of the forecast period is almost 60%. The achievement of three quarters renewable energy is achieved by a lower demand growth, limited to 3.6 times over the period.

3.3.3 Regional Growth

Although the 2100 production varies from 3.6 to 7 times 1990 levels, this disguises the marked regional differences. For Industrialised nations the production level in 2100 lies between being slightly below and 3.3 times base year production. For the reforming nations of the former Soviet Union and Eastern Europe, growth is projected to be between 1.5 and 4.8 times, and for the Developing World the increases are 12.5-19.0 times base year.

In terms of shares of global demand, Industrialised nations lose their dominance

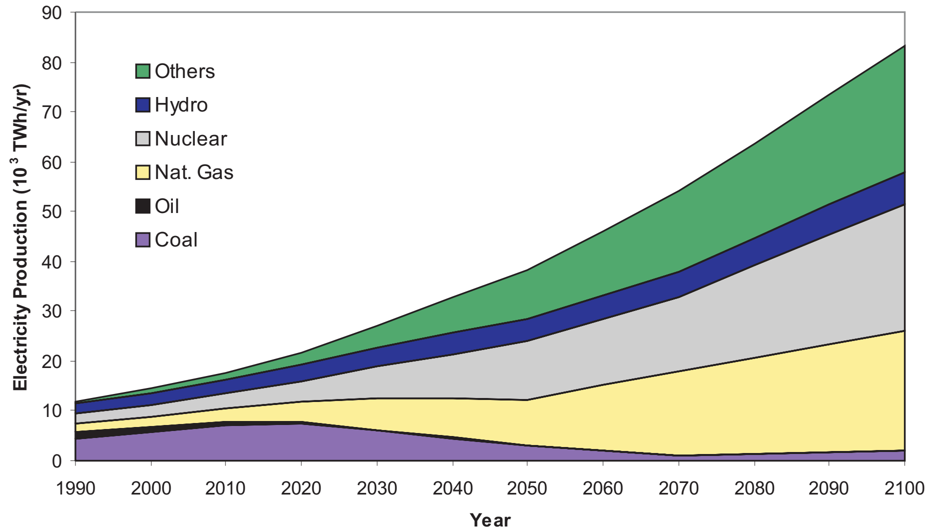


Figure 3.3: High growth WEC/IIASA electricity supply scenario A1 [74]

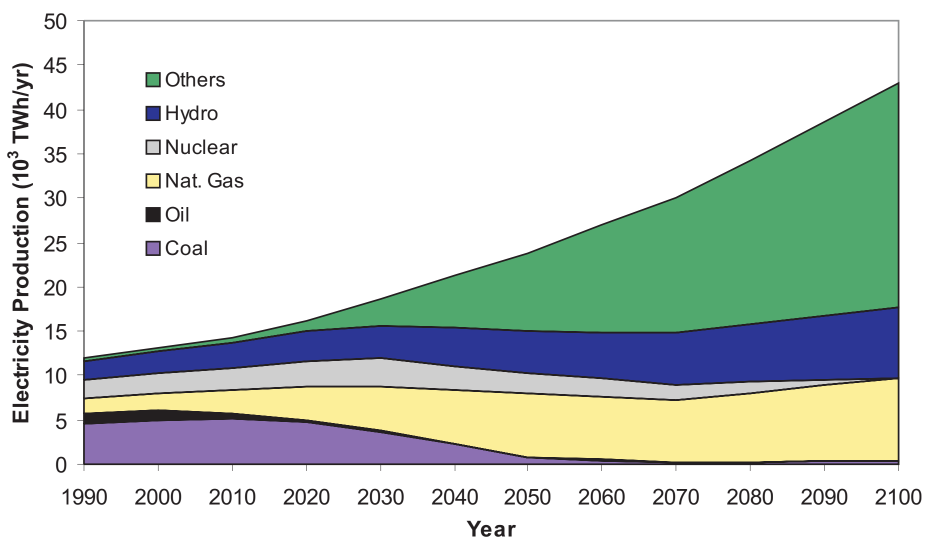


Figure 3.4: Ecologically-driven WEC/IIASA electricity supply scenario C1 [74]

falling from 60% to 17-28% over the study period. Reforming nations also lose share (from 18% to 8-13%), whilst the developing nations rise from 22% to 59-76%.

Fuel supply is perhaps even more regionally varied, reflecting indigenous resources and technology differentials. Dependent on the scenario, coal use in developing countries could be expected to increase by 1.7-4.1 times by 2100, or if the ecological approach is implemented, could fall to 18% of the 2000 level. The dominance of nuclear energy use in the industrialised nations appears likely to end under the non-ecological scenarios. By 2100 industialised countries nuclear production could represent only 20% of the total although overall production would increase by 180-390%. Such growth in developing countries would clearly be dependent on successful developments on the issue of weapons proliferation.

The key issues in regional growth are the thermo-electric efficiency of operation and the pricing strategies in developing nations. The World Bank estimates that efficiency is around 50-65% of best practice in the developed world [75]. Part of the problem lies with electricity subsidies, either for development reasons such as ensuring that many can afford it, or to secure political support. On average, electricity in developing countries is sold at 40% of its cost. This wastes capital and energy resources, making the subsidies economically and environmentally inefficient. The low prices create excessive demand, and undermine the utility's revenue base, reducing its ability to provide and maintain supplies. As a result, developing countries use 20% more energy than they would under marginal cost pricing. There is a tendency for low prices to discourage investment in new, cleaner technologies and more efficient processes.

3.3.4 Investment

The large increases in electricity demand imply a correspondingly large investment requirement. With a forecast 3.1% annual growth in electricity demand up to 2020, the requirement for additional generating capacity is high. Global installed capacity in 1996 was around 3,000 GW, with around 2% in the UK. The IEA estimate that around 1,535 GW of new capacity will be required by 2020, in addition to replacement capacity of 150 GW. This amounts to around 100 GW per year [71], and is consistent with other estimates of 117-125 GW per year [76].

The capital requirements for investment on this scale are considerable, around $100 billion a year for generation alone with a further $100 billion for associated infrastructure, up to 2020. The investments are likely to account for around 0.1-0.2% of GDP in OECD countries, 0.6-1.0% in Africa and 1.0-1.6% in South Asia. The long term IIASA/WEC scenarios suggest a range of investment requirements: $6.6-10.6 trillion over 1990-2020, $9.8-18.3 trillion 2020-2050 and $34.1-78.6 trillion for

2050-2100. These represent annual investments of $220-350 billion, $326-610 billion and $682-1,572 billion, respectively. For the EU alone, the European Commission estimate that a 1.2-1.7% annual growth in electricity demand will require investment in new and replacement generation capacity of 419-502 GW by 2020 [77]. This will cost around 542-660 billion ECU, in constant 1993 ECUs, equivalent to $490-600 billion (at US$0.9 = 1 ECU/EURO).

The achievement of these investment amounts depends on the success of attracting private capital into the electricity supply industry.

3.4 Private Capital in the ESI

Electricity generation has traditionally been undertaken by large vertically integrated and often state-owned utilities. Over the last 20 years there have been efforts in many countries to introduce non-utility generation with private capital and to reduce state involvement. The processes involved are termed 'privatisation', 'deregulation' and 'liberalisation' and are key terms in the modern electricity supply industry. The UK is one country that has undergone all of these processes.

3.4.1 UK Privatisation

The 1987 Conservative Party election manifesto included a promise to privatise the industry. The Central Electricity Generating Board (CEGB) was perceived to be inefficient, forcing electricity prices to be too high. Specific criticisms included poor productivity, over-manning, unnecessary ordering of plant, and the effective subsidising of British Coal and British Rail [78]. The Government had tried to encourage private generation through the 1983 and 1985 Energy Acts but these failed. CEGB exploitation of its monopoly position and Government interference were cited as the reasons for their failure [79]. Despite these criticisms the Monopolies and Mergers Commission concluded that the CEGB was not operating against the public interest and indeed carried out its duties well [80].

The previous and apparently successful privatisation of other public monopolies, coupled with the Thatcherite bias against public entities [81] led the Government to view privatisation as the only way of achieving a number of goals. The Government claimed that privatisation would remove the CEGB's monopoly power, curb Government interference and provide benefits to the customer (and shareholders) by removing the inefficiencies. Competition, the Government said, would force players to lower costs and the benefits would be passed on to consumers in the form of lower electricity bills. Conveniently, the break-up of the industry would also serve to remove the remaining power of the National Union of Mineworkers [78], and the revenue from privatisation would finance the Government's promised income tax cuts.

The New Industry

On the first of April 1990 the Electricity Supply Industry (ESI) in the United Kingdom was privatised. The generation and transmission monopoly the CEGB was broken up into separate companies. The twelve former Area Boards that were responsible for the distribution and supply to consumers became the Regional Electricity Companies (RECs).

Initially, the CEGB's generation capability was to be split approximately 60:40 between two private companies: National Power and PowerGen. National Power was to own the nuclear stations in order to achieve a balance. Public concern about the safety of nuclear stations, together with the inability of the Government's advisers to quantify confidently the future nuclear liabilities, threatened the sale. This forced the Government to retain the nuclear stations in the public sector [79]. The Government claimed that a competitive market was the only way of ensuring an efficient industry. However, simple economic theory suggests that the benefits claimed occur only if the market is perfectly competitive. That is, where the market consists of a large number of companies each with a small market share and no ability to set prices [82]. In fact, at vesting, the Government had created a private duopoly with an inherent danger of collusion between the two companies.

The twelve Area Boards were next to be privatised, with competition to be introduced in phases. Firstly, customers with a demand greater than 1 MW were able to contract to purchase from any supplier; and this was followed four years later for those with a demand of over 100 kW. The process was due to be completed in 1998 with a complete franchise break for all customers. In the event, this was phased in for a number of reasons, partly logistical but mainly to guarantee the sale, as until full deregulation took place the RECs would have regional monopolies, giving an opportunity to gain excessive profits. To some extent this view has been proved correct, as the lifting of the ownership restriction in 1995, led to a rash of take-overs of the cash rich RECs.

The operation and ownership of the high voltage grid was vested in the National Grid Company (NGC). NGC was initially owned by the RECs to act as a counter to the generation duopoly [79]. The RECs sold their shares at flotation in late 1995 forming the National Grid Company plc. As a monopoly NGC is closely scrutinised by the Office of Electricity Regulation (OFFER), now OFGEM.

The Impact of Privatisation

The major change that resulted from the privatisation was the change in fuel type, with coal losing its dominant position, and nuclear and particularly natural gas gaining ground, as Figure 3.5 indicates. In 1990, coal provided the primary energy for nearly two-thirds of UK electricity, but since then it has steadily lost ground. Data for 1999 indicates that its share has fallen below one third and is now second to natural gas. The share from nuclear power rose from 18% in 1990 to 25% in 1994, where it has since remained. At privatisation, there was virtually no natural gas use in power stations except for a small number of open cycle gas turbines used for peaking duty. By 1994, the proportion had risen to 15%, and by 1999, gas-fired stations accounted for just over one third of the electricity production. Oil use has declined to a position where it produces less than 1% of the total, and the contribution of other thermal generation methods (*e.g.* orimulsion) are declining. Renewable energy including hydro contribute around 2-3% of UK electricity at present.

The enormous increase in natural gas use had been termed the 'dash for gas' and occurred for a number of reasons. The UK abandoned the EC Directive restricting the burning of gas for electricity generation. The financial benefits of CCGTs were recognised and the result was that almost all new plant ordered was of this type. The lower fuel and operational costs allowed the CCGT plant to displace the large coal-fired stations from base load into mid-merit. As such their load factors fell and the energy supplied by coal as a whole declined. Boiler driven plant is not particularly well suited to being operated intermittently, due the minimum time required to raise steam. As such, the operational costs rose and they lost more ground, resulting in a significant fraction of coal-fired capacity being moth-balled or closed since 1990. The 'dash for gas' is hailed as a direct result of privatisation. However, it is conceivable that the CEGB would have followed the same path if it had been given freedom to reduce coal burn [83].

The UK generation market is becoming increasingly competitive, as more companies enter the market. In 1990, there were six major power producers, but by 1996 this had grown to 27. A number of competition measures indicate the increase in competition. One measure suggests a near halving of market concentration from 1992 to 1998, whilst the number of producers setting the market price has increased [47].

Competition and the use of natural gas have led to falling domestic and industrial electricity prices. Since 1990, domestic prices have fallen by 15.5% in real terms, or nearly 20% if taxes are excluded, whilst industry has seen its electricity prices fall by 24% in the same period. Competition in domestic supply is anticipated to lower costs by several percent [47].

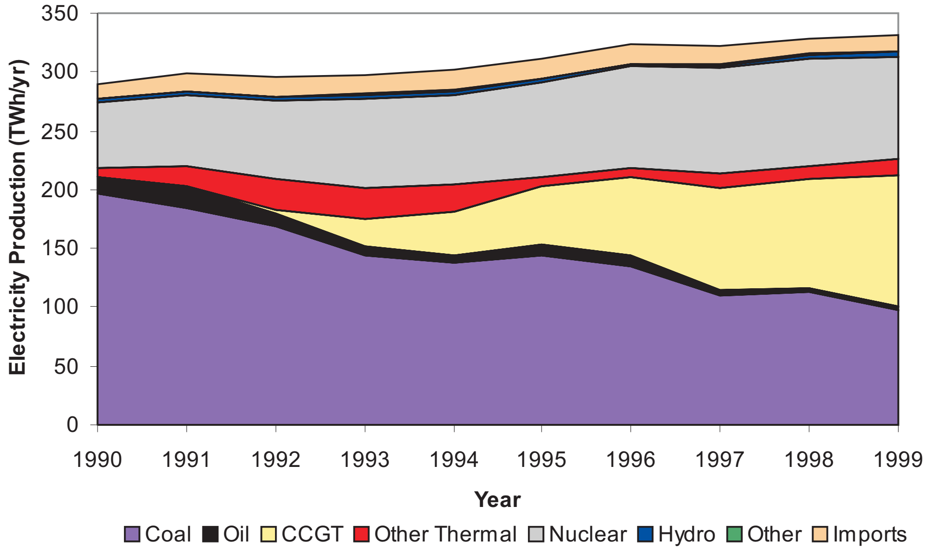


Figure 3.5: UK electricity generation by fuel source 1990-98 (TWh/yr) [84, 85]

3.4.2 Electricity Markets

Other than the UK, much of the EU, Norway, Chile, Argentina, Australia, New Zealand and the USA, have seen or are undergoing a drive towards deregulation and privatisation. The primary aims of the privatisation of the ESI in the UK were to ensure competition and the involvement of private capital in the industry. The European Union is following suit, with a 1997 Directive requiring that member states move towards competition, and as an initial step ensure that 25% of energy is generated by non-state enterprises. In the US, private capital has long been involved with electricity supply, and is dominated by around 200 private utilities covering 72% of the market [83]. The dominance of the utilities was partially addressed in the 1978 Public Utilities Regulatory Policy Act (PURPA) [86]. The act required, among other things, that utilities purchase power from smaller generators at the price equal to the utility's own avoided cost. The aspect of UK privatisation that has been adopted and implemented by other countries undergoing deregulation is the creation of an Independent System Operator to operate the transmission system as a common carrier.

Perfectly competitive markets ensure that producers sell when the market price is at least equal to their marginal cost [82]. With electricity generation, if no player is able to influence the market price, then all generators will offer energy for sale (or bid) at their marginal cost. To ensure competition in all or part of the ESI, electricity markets have been introduced. A number of distinct models are in use or under consideration.

Wholesale Pool

This model was first implemented in England and Wales, and all energy is traded between generators and suppliers through the 'Pool'. The market clearing price is set in advance on the basis of the merit order schedule. Bids from generators are invited a day ahead, and an unconstrained schedule is created from them, lowest first, until the expected demand level is satisfied. The bid price of the last generator scheduled in any period is the system marginal price, and all generators receive this energy price [87]. The effect of transmission constraints are then examined, resulting in some cheaper generators being asked to not generate, and some more expensive ones required to do so. The costs of compensating the cheaper generator, and use of the expensive generator are shared between the suppliers, and this known as 'uplift'. Many suppliers sign 'contracts for difference' (CfDs) with generators, to hedge against the volatile pool price and adjust prices to an agreed strike price.

Another key aspect of competitive markets is that the customer should be able to choose their supplier. Termed as the 'franchise break', the local monopolies of the RECs have been slowly dismantled and from November 1999 (albeit 18 months late) all UK domestic customers have been able to select their own electricity supplier. The RECs are still responsible for their distribution grids, but are now required to give open access.

There is a tendency for Pool prices to rise considerably at times of high demand. This is partly as a result of the capacity payments paid to generators to encourage them to make plant available at these times. The capacity element is based on the loss of load probability (LOLP), and there is evidence that the larger Generators have been abusing their market power by restricting the availability of their marginal plant, pushing up the system marginal price and the capacity payment [88, 89].

The wholesale pool tends to create a globally optimum schedule and lower overall costs, but requires competition to be perfect. The abuse of market power and the perceived lack of competition have led to the New Electricity Trading Agreement (NETA), scheduled for implementation in October 2000. This is based on a system of bilateral trading.

Bilateral Trading

Energy is traded directly between Generators and Suppliers through bilateral contracts, and residual supply and demand imbalances are settled in a net pool. The contracts are not made public and the system is therefore criticised as not being fully competitive [83]. In Norway and the future UK system, a trading market resembling that of the financial markets are used for day-ahead contracts and futures trading to allow hedging. The overall solution is unlikely to be optimal, although individual players may achieve this, and overall system costs are likely to be higher.

Single Buyer

A nominated authority, often called the Purchase Authority (PA), acts on behalf of consumers, to buy energy from generators. The system has a number of advantages; competition exists in generation, the consumers should receive an optimal price, and generation and transmission development can be coordinated ensuring a reasonably high level of system security. However, the purchasing authority is a monopoly, and should be prevented from owning a generator. The approach is suitable for mixed state and privately owned generation and is favoured in France and Italy as well as being implemented in a number of developing countries [83, 57].

Market Comparison

The choice of market structure is dependent on the development of the system in question. Developing countries require a stable environment in which to fund major generation and transmission schemes. As such, the state may be required to play a major role in the running of the utility to underwrite the contracts. More developed systems can probably support competition in order to improve operating efficiency.

A monopoly utility's greatest embarrassment would be a supply failure, and this in part accounts for the apparent over-investment. Single Buyer systems avoid most of the monopoly's inefficiency, albeit at the expense of security. The fully competitive pool systems have low system security relative to the monopoly. Competition in generation is estimated to lower costs by around 10% through more efficient generation cycles, but the integrated planning approach saves around the same percentage in avoidable interest by ensuring ideal plant margin and generation mix [83].

3.5 Private Investment

Traditionally, the supply of electricity was viewed as a service, but now with deregulation it is viewed much more as a commodity to be bought and sold, and as a means of making money. With integrated utilities the provision of electricity was concerned with its supply in a secure manner and at least cost. In the state sector other targets included ensuring security of supply and job preservation by the use of indigenous fuels. Money was important but the profit was not an over-riding goal. State utilities, like the CEGB, had to meet an overall rate of return on their assets, so asset re-valuations would occur on a regular basis to ensure this.

The introduction of private capital shifted the focus, and a suitable profit on the investment became the primary concern. Other than the companies formed from the break-up of former state utilities, most of the new capacity added in the UK and elsewhere has been from Independent Power Producers (IPPs) who have entered the market when new capacity was required. Often project specific, the ownership of the IPP depends on the market in which they are operating. In developed countries with adequate capacity and minimal state intervention and control, most IPPs are wholly owned. In developing countries, projects normally require a sponsor, which is usually the government or one its agencies. In many countries, and particularly for hydropower projects, the sponsor will not want to allow the developer full control over national resources [57]. In this case, the agreement will feature the ownership of the facility reverting to the public after a specified period, as in build-own-operate-transfer (BOOT) schemes.

3.5.1 Project Finance

Most power projects are project financed, with the investors often creating a new company for the purpose, which limits their risk. As the company has no track record to support its financing request, lenders and investors must look to the anticipated cash flow of the project to indicate repayment of the loan principal and interest, and a return on the investment. They are supported by a series of complex contracts between the parties to the project. In the event of a default, the project's assets are used as collateral, but generally there is no claim on the assets of the parent company or project sponsors, which is termed non-recourse financing. Alternatively, they may be able to lay claim up to project completion (limited recourse). Risk assessment therefore plays a large part in the lender's analysis. Project financing is split between equity and debt, with the majority as debt. Typically, the debt proportion is around 70%, and varies with the lender's perception of the risk [90].

The necessary debt finance can be sourced from export-credit agencies, multilateral organisations like the Investment Finance Corporation (the World Bank's commercial arm), commercial banks or international bond markets [76]. The equity component comes from the sponsors, from others parties to the project or international institutions.

3.5.2 Corporate Finance

Many of the larger, and in particular oil, companies finance electricity projects from their balance sheets. The debt-equity ratio is much lower, with debt representing only 30% of the total. Clearly, the company is putting itself at risk by financing in this manner, but there are a number of important advantages. Firstly, the company can use its reputation and past performance to raise debt more cheaply than for project finance, and as the risk is diversified its cost of equity is also lower. Secondly, the transaction costs are lowered as the complexity of contract negotiation is avoided [91]. Finally, outside lending is more likely as corporate financing is less risky to lenders as the risks are more diversified [90].

One way of reducing the risks are for developers to 'pool' the assets of different projects, and as such the equity and debt providers are financing more than one plant. It can also mitigate country specific risk, and for those with operational plant, the revenue stream will assist in repaying debt and paying dividend. Larger companies are also at an advantage with their greater access to capital and more experience, and this accounts for the increase in mergers and acquisitions in the sector. There is a trend towards generation investment being financed on this basis [91].

3.5.3 Contracts and Power Purchase Agreements

Contracts are key to ensuring the correct spread of risk and in creating conditions in which investment in electricity supply will thrive. The Contacts for Differences (CfDs) used in the UK Pool are a form of financial instrument known as a 'swap'. With the bilateral trading system, increased use will be made of financial instruments including options, as well as futures to hedge the price of energy.

One particularly important contract is the Power Purchase Agreement (PPA). This is a contract for the sale of energy, availability and ancillary services from an IPP. The buyer is dependent on the market structure. In single buyer systems the buyer will be the power purchasing authority, whilst in more deregulated systems the suppliers will often contract to purchase electricity from a number of different IPPs in order to supply their customers [92]. Tendering for energy supplies can be carried out competitively or through negotiations with a single bidder, with the former deemed to result in lower costs to the purchaser [93].

The PPA will specify an agreed price for energy. Early contracts relied on the energy price to cover all the costs of the plant, and were fixed at a price equal to their average cost or the purchaser's avoided cost (as in PURPA agreements), for a specified level of output. As long as the this level was reached, all the costs were covered. However, such contracts do not ensure efficient operation of the plant. Assuming that the energy price agreed is greater than the IPP's variable cost, then there is little incentive to dispatch it efficiently. The owner of the IPP will wish to operate at all times and this will tend to displace cheaper plant. Alternatively, the inflated price implies that the system operator will dispatch it at times of high demand, and as such the plant will be displaced by more expensive alternatives [92].

More efficient operation occurs if the energy price is set at the marginal cost of generation, which includes the variable component of operations and maintenance expense. The IPP will bid and be dispatched at their marginal cost, in a similar manner to a perfectly competitive market. The energy price could be simply a price per unit of energy, but it is more likely to be related to the level of output, for example start-up. Figure 3.6 shows an example of the variation in generation marginal costs with output, and is in the form required for generation bids into the UK Pool. The energy price may be fixed or linked to fuel prices, to prevent the owner being exposed to significant risk when the fuel price rises. If no fuel cost link is agreed then a rise in fuel price will lead to the plant making a loss on all production [92].

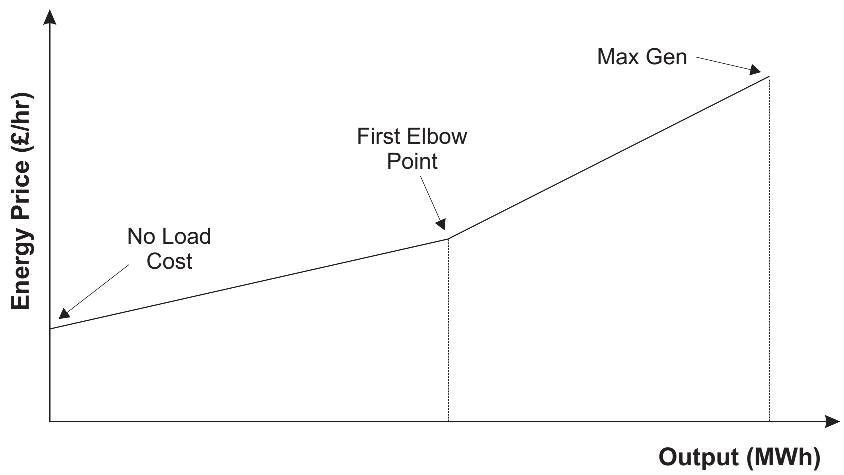


Figure 3.6: Thermal generation marginal cost curve, *Willans' Line* [73]

If the energy price reflects the marginal cost of the energy, then there must be some payment to assist in covering the fixed charges (*e.g.* interest). This payment is termed an availability payment, and not only covers the fixed costs but provides an incentive to be available when system demand is high. This is most important to mid-merit and peaking plant, that whilst they are more expensive are still vital to meet demand.

The availability payment normally agrees a target level of availability in terms of the power output and the hours in a particular period (year, month, *etc.*), as well as an annual payment to cover non-variable costs and a normal profit. The agreement would also specify a system of bonuses and penalties for exceeding or missing the target. In some systems, like the UK Pool, it is the system operator that partly pays the generator for availability. These are in the form of capacity payments and reflect the value of the generator to the system as a whole [83].

Some power purchase agreements, particularly those between the generator and the system operator specify the remuneration, if any, for providing ancillary services, such as frequency control, spinning reserve, reactive power support and black start capability. These are generally covered by lump sum payments although the UK has been moving towards a market in reactive power [94].

Power purchase agreements tend to stabilise the revenue of the IPP, and as such reduce the price risks to both the IPP and the buyer. Virtually all new plant built by IPPs in the UK following privatisation was covered by a long-term PPA with a REC [76], as it formed the basis for securing loan capital, by ensuring a predictable revenue stream with which to repay the loan.

With the trend towards corporate financing, there is less need to undertake a long term power purchase agreement. Building and operating on this basis is termed merchanting and it is increasingly common in developed markets [57]. Despite this the operators will generally enter into contracts to limit the price risk.

3.5.4 Scope for Private Finance

Given the enormous increase in electricity production expected over the next 100 years, and the requirement for massive increases in generating capacity, finding the investment required may not be possible for state-owned utilities, particularly those in developing countries. Restrictions on public finances and public borrowing, limits the ability of the state-owned company to fund expansion. The result is that private investors are expected to provide the finance for much of the new and replacement generating plant over the next century. The range of estimates for the proportion of capacity addition from private sources varies [76].

Siemens estimate that 32% of their future fossil-fuelled plant sales will be to IPP's and a further 23% to privatised and commercial utilities. Cambridge Energy Research Associates think that between one quarter and one third of all new capacity, outside North America will be for IPP's. InterGen estimate that 191-617 GW of new Asian capacity installed between 1997 and 2010 will be IPP. However, others suggest that, due to slow progress towards liberalisation, only 18% of total capacity addition over the period 1990-2020 would be from IPPs [95].

During 1991-1994 private investment accounted for only 11% of new capacity, so a range of 16% to 33% for private investment is not unreasonable, and would represent investment in around 17-41 GW of new capacity each year. The penetration in developing countries is likely to vary considerably, with Chile expected to be nearly all privately financed and China only around 11% [76].

3.6 Implications for Renewables

Given the drive towards liberalisation and deregulation of electricity supply, private power will affect the ability to reduce environmental burdens.

3.6.1 Short-termism

The key outcome of market systems and in particular private finance, is that investment decisions are based purely on the trade off between risk and reward. Methods that are quickly implemented, with lower capital costs, and result in a faster payoff, are favoured over those with higher capital costs and longer debt repayment periods. Payoff period is considered as a proxy for investment risk, despite the fact that the method does not take into account the time value of money. When discounting techniques are used, the higher capital cost projects are often proven to be the better long-term investment.

So called 'short-termism' is common with capitalist economies but is particularly apparent in the UK and is considered to be one of the key reasons for its economic failings [81]. When applied to electricity supply it results in great interest in gas-fired plant that return a quick profit, but only limited interest in renewables. This means that most renewable energy technologies are not covered by the same development effort concentrated on making CCGT plant cheaper and faster to build and operate. As a result, the potential decline in the cost of renewable energy is held back, and it continues to be unable to compete.

3.6.2 Externalities

Although fully competitive markets do allocate resources efficiently, and tend to produce at lowest cost, they do not include social costs or benefits. The result of the failure to include externalities or external costs is that the social market outcome is not optimal.

The environmental effects of electricity generation (summarised in Section 3.1) are all external costs, while improved life expectancy would be an external benefit. These factors are not included in the price of electricity and as such result in different quantities and sources of electricity than would occur if a true social market equilibrium occurred. This omission has serious implications for the use of renewable energy.

The internalisation of these external costs is an issue of intensive research effort. The ExternE study by the EC was a major attempt to quantify, in monetary terms, the environmental impacts of electricity generation [96]. For each major energy resource, including hydro and wind power, damage costs were assigned to particular aspects of their impacts, including health and the environment. Those damages that do not have a direct and measurable impact, for example, the loss of visual amenity due to the construction of a wind farm, are estimated on the basis of the contingent valuation method (CVM). This estimates the value of the damage by considering individuals' 'Willingness to Pay' (WTP) to avoid the damage, or a price required for them to accept it, called 'Willingness to Accept' (WTA). This methodology and others are fraught with problems, and resulted in a wide range of estimates of damage for each fuel cycle.

With careful development and consensus on damage costs, such valuations of impact could be used to correct the market failure by adding the external costs to the financial costs of electricity generation. This would raise the price of the electricity for each fuel cycle and would tend to improve the overall position for some fuel cycles, such as renewables, and worsen others, particularly coal. This system could work to directly alter the marginal cost functions of different generators, and hence scheduling could be on the basis of least marginal social cost. This would result in an increased interest in fuel cycles with low social costs, effectively forcing investors to take account of environmental impacts in their financial decision-making.

The current UK system of bidding on the basis of marginal cost would be ideally placed for such a system. However, the incoming NETA would be less well suited, and as such the UK may have lost an opportunity to improve its environmental record.

3.6.3 Financial Support

In the absence of internalisation of social costs, the financial position of less damaging forms of generation can be improved through:

- direct subsidy,
- taxation,
- renewable obligations, or
- tradable emissions permits.

Although the World Bank and others appear opposed to subsidies for power generation, due to the market distortion effect, much of their opposition is related to subsidies for fossil-fuel use. Subsidies such as 'green power', or the use of taxation would assist in moving the market allocation towards the social optimum. However, both tend to lead to inefficiencies [46].

Renewable obligations such as the UK NFFO were successful to an extent, although many projects failed due to lack of planning consent or the cost of line upgrades. Until renewable energy projects are accepted more fully by the public and the problem of mandatory upgrades are tackled, obligations may not be overly successful.

Tradable emissions permits could be the most suitable method for stimulating interest in non-polluting energy sources, by in effect, requiring the fossil-fuelled stations to subsidise the renewable forms, and giving them a valuable source of income.

3.6.4 The Future for Renewable Energy

The tendency towards short-termism is a serious problem for renewables. In the absence of full-cost pricing, other methods are required to move towards a social market. In the longer term, renewable energy is likely to be in demand as perceived shortages of fossil fuels result in higher fuel costs and a renewed effort to find alternatives.

3.7 Summary

The electricity supply industry is a major contributor to regional and global environmental damage, and it is right that attention has been focussed on the industry to reduce its impact. While many of the pollutants are relatively simple to mitigate it is the emissions of CO_2 that are the major difficulty, not least that the majority of electricity is derrived from fossil fuels. A variety of methods are described with how to reduce carbon emissions, of which increased use of hydropower is one.

Electricity demand and economic development are strongly linked, and as the developing nations try and reach Western standards of living, the demand for electricity is set to grow enormously over the next century. One of the consistent features of scenarios of future electricity generation is the continued expansion of hydropower production, which is forecast to grow by at least three times by 2100.

The massive investment required to meet the demand is such that it appears to be possible only with the assistance of private capital. Privatisation and liberalisation, two processes featuring heavily in the late twentieth century are set to be repeated throughout the world. However, the consequent treatment of electricity as a commodity is not without risks. In particular, the tendency towards quick financial returns does not favour renewable energy sources such as hydropower. As such, the needs of private investors may run contrary to the need for emissions reductions.

Chapter 4

Climate Change and Hydropower

The chapter commences with an overview of the relationships between climate, climate change and the electricity supply industry. It then focuses on potential climatic change impacts on the hydrological cycle before examining the implications for hydroelectric power provision. Available literature is reviewed, key studies examined, and the limitations of existing approaches identified. Finally, the preceding two chapters will be brought together in a detailed consideration of the potential impacts on hydropower investment.

4.1 The Electricity Sector and Climate Change

The preceding two chapters describe how, through the use of fossil fuels in generating electricity in order to satisfy consumer demand, the electricity supply industry is contributing to the global warming problem. As with all complex systems, the interaction between electricity supply and climate are not restricted to simple cause-effect processes. In fact, second-order effects are numerous and affect the whole of the ESI from generation to demand.

4.1.1 Climate Feedback

Electricity Demand

Electricity demand is sensitive to climatic fluctuations and in particular temperature change. Rising temperature resulting from climatic change will have two effects: it will tend to lower the requirement for space heating, but raise the demand for cooling.

Whether electricity demand rises or falls as a result of temperature rise depends on the type of climate and the relative importance of electricity in providing heating and cooling services. Areas with a summer peak demand will find demand rising, while those with a winter peak, may find demand falling. It is uncertain which will be the stronger pressure, but some regions may undergo a shift in peak demand from winter to summer. A number of studies have considered such changes either in exclusion or as part of a supply-demand comparison [97, 98, 99] and a good review of methods is given by Jager [100]. Irrespective of the pattern of change, a rise in electricity demand is likely to increase carbon emissions if fossil fuels are used to meet the shortfall.

Investment

Rising demand implies a need for investment in generation and transmission facilities, but few studies have examined this aspect. Linder and Inglis considered the demand requirement for the United States for temperature rises of 3-5°C by 2055. They concluded that peak demand would increase by 13% above the baseline projection, requiring commissioning of 5-7 GW of capacity at an increased cost of 5-7% [101]. The requirement would be for peaking plant rather than base load, altering the fuel mix. The differing regional impacts could increase the requirement for regional energy transfers. Overall, the increased construction and fuel use would lead to greater environmental damage.

Extreme Weather Effects

Climate change is anticipated to lead to increased incidence of extreme weather and therefore increased transmission system disruption due to storm damage. Situations similar to that experienced by New England and south-eastern Canada in January 1998 could become more frequent. Then, over three million people were without power for almost a week after ice storms brought down transmission lines.

Thermal Generation

A rise in ambient temperature will reduce steam and gas cycle efficiencies slightly. Stations sited on the coast may be threatened by sea level rise and could require expenditure on protection facilities. Also, thermal stations sited inland may be vulnerable to output restrictions enforced by reduced water availability or thermal pollution. Situations similar to this occurred during droughts in France and the US [102]. However, the widespread use of CCGT stations should lessen vulnerability as their cooling requirements are lower [103].

Renewables

Impacts on renewable energy resources represent another important climate-energy feedback, and they constitute changes in resource availability, operational performance and therefore the willingness to develop resources. A brief description of key impacts follows but a fuller discussion can be found elsewhere [100, 102].

Wind energy depends partly on the temperature gradient between equatorial regions and higher latitudes. The relatively greater warming of higher latitudes predicted by GCMs suggests that the wind resource may reduce. Fortunately the effect of local geography in determining the wind regime may limit the sensitivity of sites to warming. The cubic relationship between power output and wind speed means that changes in wind speed are amplified, with one estimate suggesting that a 10% change in wind speed could alter energy output by 13-25% [104]. A change in prevailing wind direction could be problematic for existing installations dependent on the array orientation.

The performance of direct solar technologies are sensitive to atmospheric conditions, and increases in humidity or cloudiness due to climate change may lower their output. Although there are few projects planned, ocean energy systems would be susceptible to storm damage and would need to take account of rising sea levels.

Rising temperature and changes in precipitation patterns will alter river flow regimes and consequently affect hydropower production.

4.1.2 Analysis Requirements

The high economic value of the electricity supply industry, but more importantly, the now essential requirement for dependable power supplies, suggests that changes or threats to the future means of production and distribution of electricity need to be assessed effectively.

To this effect, and given the current significant contribution of hydro-electricity to global electricity production, the remainder of this chapter is given over to an analysis of the potential impacts of climatic change on hydropower.

4.2 Changes in the Hydrological Cycle

The hydrological cycle (Figure 4.1) is closely interlinked with the climate system, and, as such, alteration of the climate through increasing greenhouse gas concentrations, will lead to changes in hydrological systems.

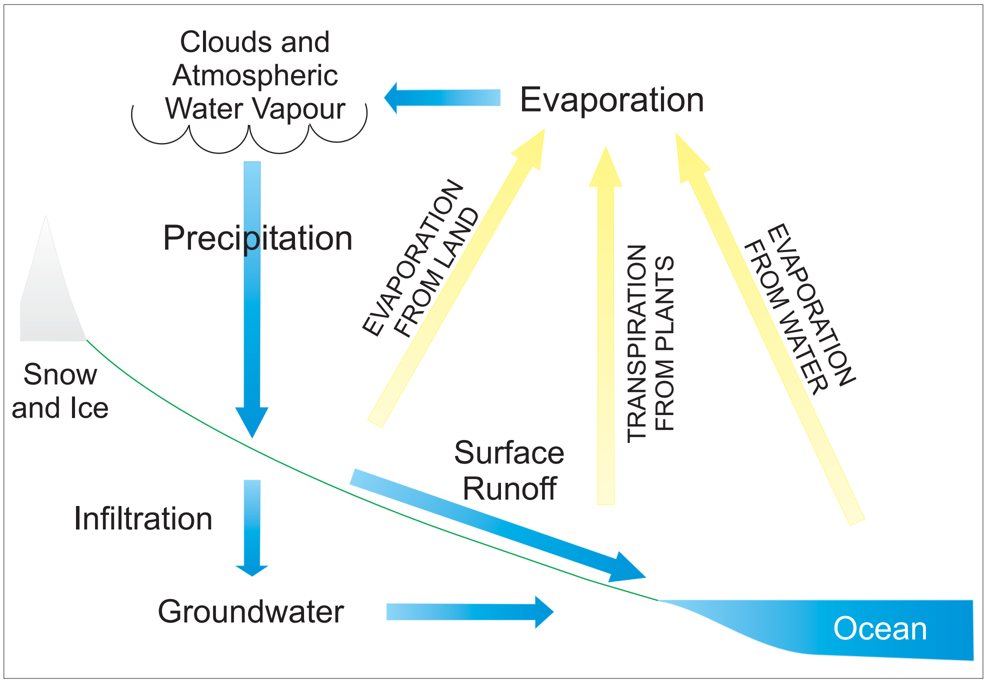


Figure 4.1: Climate and the hydrological cycle

4.2.1 Precipitation

Precipitation is the primary variable in determining hydrological characteristics, and changes in quantity, timing and intensity will have a profound effect on many aspects of the hydrological cycle including the alteration of river flows. Current predictions from General Circulation Models are that global mean precipitation will increase by 3-15% for a temperature rise of 1.5-4.5°C (see Chapter 2). Some areas will see increases, others decreases and there is little agreement as to the quantity or regional distribution of the changes. However, higher latitude regions are expected to experience more precipitation especially in winter, but there is no consensus on the pattern for the tropics.

4.2.2 Evapotranspiration

Potential evapotranspiration (PET) is the maximum possible rate of moisture removal from soils and is determined by meteorological conditions and plant physiology. PET is made up of evaporation from surfaces and plant transpiration.

Potential evaporation (PE) is determined primarily by net radiation and temperature but also by the moisture-holding capacity of the air and other factors (*e.g.* wind speed). Increased temperature will lead to more evaporation, although the effect is complicated by an increase in the moisture holding capacity of air, which further enhances the evaporative effect, particularly where humidity is the limiting factor [105]. In such a region, a rise of 2°C could raise potential evaporation by up to 40%, although this would be lower for an arid climate [106].

Plant physiology controls the rate of transpiration, with the aerodynamic resistance affecting airflow across the plant, and stomatal resistance restricting the release rate. Plant properties are expected to alter with climate change, leading to changes in the PET rates. These include changes in the timing and rate of plant growth, the vegetation mix and the effects of CO_2 enrichment. Experiments suggest that stomatal resistance may change and that some plants will experience higher growth rates, although it is difficult to generalise the conclusions [107].

Overall, PET rates have been found to increase 3-4% per degree Celsius of temperature rise [108, 109], however, the increase in the actual evapotranspiration (AET) rate is likely to be lower. As its definition suggests PET determines the quantity that could evaporate with an unlimited supply of water. In practice, moisture availability is limited, and so the actual rate is lower. As such if moisture levels decline, AET could follow suit even though the PET has risen. Either way, changes in PET and AET will alter catchment water balance.

4.2.3 River Flows

The balance between water entering the catchment as precipitation and leaving through evapotranspiration determines the quantity and timing of catchment runoff which ultimately becomes river flow. Changes in both precipitation and PET are expected as a result of climate change, and so changes in river flows are also anticipated. Whether runoff increases or decreases will be decided by the relative magnitude of the changes and other factors including the ability of the soil to absorb and hold moisture. As such, even with the projected global precipitation increases, river flows may decrease [105].

Rising temperatures will alter precipitation and evaporation patterns which, mainly through changes in soil moisture, force changes in river flow regimes and groundwater storage levels. Ecosystems will affected by changing climate and increased CO_2 levels which, in turn, alter the water balance and quality of the catchment.

Changes in the mean values of precipitation and temperature will alter not only mean river flows, but also their variability. Catchments exhibit varying degrees of non-linear behaviour and it is this that leads to alterations in variability. Similarly, altered variance could well imply a change in the mean output [107]. Figure 4.2 shows both effects, although the actual response will depend on the characteristics of the catchment. Small mountainous catchments will be more affected by changes in storm rainfall, while large river basins, which tend to average-out short term fluctuations, will respond to changes in prolonged rainfall.

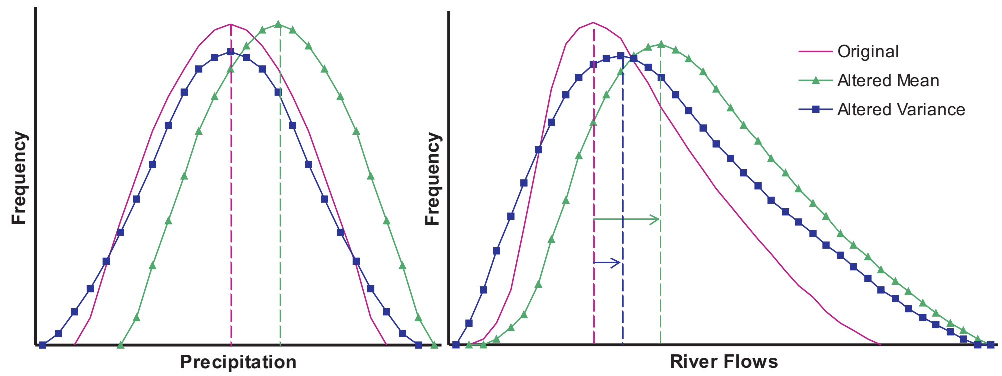


Figure 4.2: Effect of altered precipitation mean and variance on river flow distributions [107]

Many catchments are dominated by snow cover or glaciers, where the snow stores water over the winter, releasing it slowly and augmenting summer low flows. Higher temperatures will lead to increased winter runoff as more precipitation falls as rain, reducing the quantity of water stored in the snowpack and reducing the amount available in spring and summer [105]. As Chapter 2 highlighted, glaciers worldwide are retreating and this process is expected to continue and accelerate. This is predicted to lead to artificially high river flow as the glaciers are 'mined', although they would reduce considerably once depletion is complete. Detailed assessments of the potential for change are difficult, particularly in the developing world, as monitoring of mountainous regions is currently inadequate [110].

The following section introduces the means of estimating future river flows and indicates the nature of the changes implied by previous studies.

4.3 Projections of Future River Flow

A wide range of studies have considered the impact of climatic change on river flows, either by the direct estimation of hydrological changes or through the use of hydrological models. The vast majority of studies in the literature rely on hydrological models to convert changes in climate into estimates of river flows. However, there are some notable examples of direct estimation, which have the advantage of being relatively simple to apply over large areas. Both used the runoff data from GCMs to determine flows in specific rivers. The first study considered changes in annual runoff for over thirty major world rivers using the the GISS model [111], whilst the US Environmental Protection Agency (EPA) examined future US river flows as indicated by a range of models [112].

The studies generally consider the differences between a base case, assumed to be the 'current' climate, and a future climate as specified by either arbitrary changes in climate variables or from the output of GCMs. The base period normally used is 1961-1990, as specified by the World Meteorological Organisation (WMO). This period could be seen to already incorporate some degree of warming, including the warm 1980s, and therefore it is not strictly an indication of the change before and after climate warming, rather it is a practical compromise given the availability of data.

4.3.1 Annual Flows

The change in river flows brought about by changing climate can be illustrated most simply by the use of annual river flow volumes. Almost all studies have considered this aspect, but despite the differences between study methods, models or catchments, there are two notable findings:

- Annual runoff is relatively more sensitive to changes in precipitation than potential evapotranspiration;
- Changes in precipitation lead to proportionately greater changes in runoff.

The relative sensitivity of runoff to precipitation change is higher than for temperature, and the differential increases in drier catchments. At the very least a 10% increase in annual precipitation offsets the effects of increased PET caused by a 2°C temperature rise [107].

Changes in mean flows tend to alter by a greater proportion than mean precipitation, implying some form of amplification. The amplification effect is more apparent in arid climates, and arises as the difference between precipitation and PET changes to a greater extent than precipitation alone [113]. The existence of the greater hydrological 'elasticity' of arid basins is confirmed in a study by Reibsame *et al.* of five major rivers across three continents [114]. Figure 4.3 shows a stylised relationship between the runoff coefficient (runoff (R)/precipitation (P)) and dryness index (PET/P) of the basins, and the wide range of hydrological responses. Overall, climate sensitivity increases with lower runoff coefficient and higher dryness index and accordingly the Nile is found to be most sensitive.

The sensitivity of a catchment to both temperature and precipitation change can be determined by the application of uniform hypothetical changes to the climate variables. Table 4.1 indicates the range of sensitivities of annual runoff volumes to a temperature rise of 2°C and precipitation change of up to 20%. The variations can

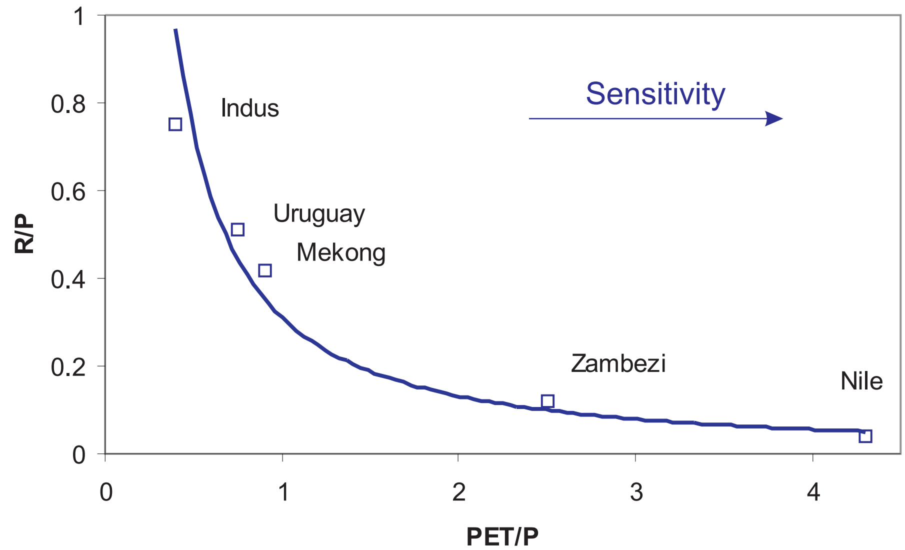


Figure 4.3: Relative dryness of five major rivers [114]

be accounted for by the differences in climate types and the methods of determining potential evapotranspiration. Again the greatest sensitivity is seen in the catchments with the lowest runoff coefficients (*i.e.* Nzoia).

River	Reference.	% Change in Precipitation -20	-10	0	10	20
Saskatchewan, Canada	Cohen (1991) [115]	-51	-28	-15	11	40
Yalong, China	Deng & Hou (1996) [116]		-20	-6	7	
Mesohora, Greece	Mimikou *et al.* (1991) [117]	-32	-18	-2	11	25
Nzoia, Kenya	Nemec & Schaake (1982) [118]	-65	-44	-13	17	70
Indus, Pakistan	Reibsame *et al.* (1995) [114]	-19		-1		18
Delaware, USA	Wolock *et al.* (1996) [119]	-23		-5		12
Upper Colorado, USA	Nash & Gleick (1991) [120]		-23	-12	1	

Table 4.1: Runoff changes for hypothetical 2°C temperature rise and percentage change in precipitation

While uniformly applied changes give some indication of the sensitivity of catchments to changes in climate variables it does not allow projections of future conditions. GCM scenarios or those derived from them, give a more useful idea of future river flows.

Studies using the UK Climate Change Impacts Review Group (CCIRG) climate scenarios have indicated marked regional differences in runoff change [121]: regions north of Manchester experience increased runoff of at least 5% with some areas, particularly the Scottish Highlands estimated to see increases of 15% and above;

areas to the south of a line between the Severn and the Humber would see decreases of at least 5%, and the south east would see reductions of 25%.

GCM scenarios also indicate the amplification effect and the sensitivity to precipitation change (Table 4.2).

GCM	Precipitation (%)	Temperature (°C)	Runoff (%)
GISS	-3	4.5	-12
GFDL	19	3.6	22
UKMO	4	5.6	6

Table 4.2: Runoff scenarios for the Uruguay River for three GCMs [114]

4.3.2 Monthly Flows

Although changes in annual flows are a useful measure of catchment sensitivity, they tend to disguise seasonal changes. A climate scenario may result in mean flows similar to current observed flows but exhibiting a different flow regime [122]. Studies in the literature have found that a certain amount of seasonal change occurs, the extent depending on the characteristics of the catchment as well as the scenario of change.

The major change to flow regimes appears to be due to a change in the amount of precipitation falling in the form of snow (*e.g.* [123, 117, 124]). In regions where winter precipitation is at present dominated by snow, rising temperatures will tend to increase the proportion of rainfall, which will consequently lower the volume of the snowpacks. This will lead to a smaller spring melt and an increase in the proportion of flows occurring in winter, although the change in volume follows the change in precipitation.

Studies of the Mesohora basin in central Greece illustrate the effect [117, 125]. Figure 4.4 shows the alteration of the runoff regime for a temperature rise of 4°C and a 10% decrease in precipitation. Although annual flows decrease 21%, spring flows decrease by over a third, and summer flows more than halve (55%). The proportion of flow in the winter increases from 38 to 50%, and spring flows decrease to 31% of the total.

A second important determinant of change is the ability of the catchment to store moisture. Permeable catchments tend to be able to store water during periods of high availability and release it during periods of lower precipitation. Less permeable catchments will turn the extra winter rainfall directly into runoff, and consequently

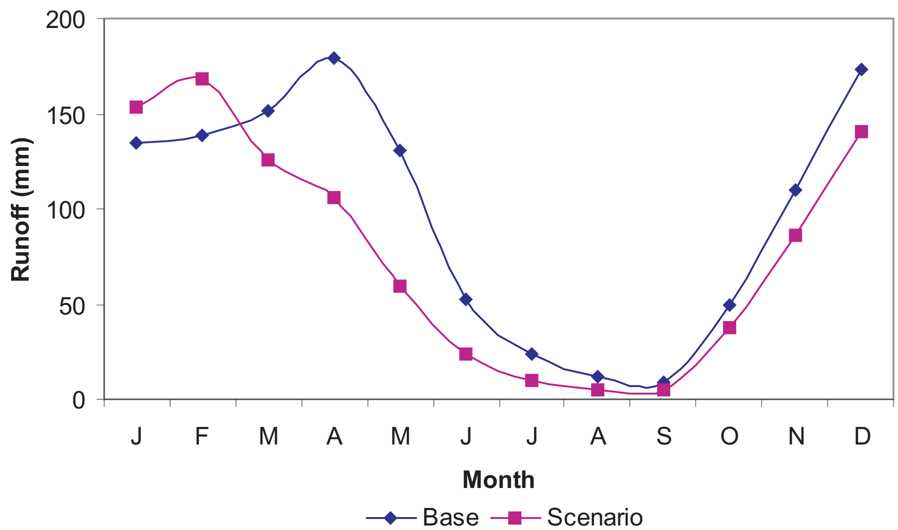


Figure 4.4: Monthly runoff in the Mesohora basin, Greece, for current and altered (Δ P = -10%, Δ T = 4°C) climates [117]

will experience lower flows during the summer months. Climate scenarios that project precipitation to be higher in the winter and lower in the summer will tend to amplify the winter/summer differences. Catchments in south east England are expected to follow this pattern and could experience reductions of summer flows of more than 50% [121]. Such changes in seasonal flow are expected to lead to changes in the characteristics of floods or droughts.

4.3.3 Extreme Flows

Alterations of the flow regimes of rivers will alter the frequency of exceeding particular discharges. Of particular interest is the effect of climate change on low and flood flows.

Increases in drought or low river flows are often cited as a possible outcome of climate change. However, rainfall is only one determinant, with catchment storage and other characteristics playing a major part. Studies in the UK indicate a mixed response from catchments, although the majority experienced a fall in the flow exceeded 95% of the time, and several catchments saw their low flow values halved [121].

Climatic change is expected to increase flood occurrences and consequent damage. However, relatively few studies have considered flood frequency and magnitude, mainly due to difficulties in creating sound scenarios for changes in flood-producing climatic events (rainfall or snowmelt) [126].

The quantity of rainfall required to create flooding is dependent on the characteristics of the catchment (*e.g.* permeability) and the state of the catchment at the time of rainfall. Wet or saturated soil requires much less rainfall to create flooding. The size of the catchment is also a factor, with flooding in larger catchments sensitive to longer-duration rainfall, and small catchments ones susceptible to intense rainfall events.

Rainfall intensity is expected to increase, or rather the frequency of intense events will increase, due partly to an increase in convection. Snowmelt flooding characteristics will be altered by the temperature increase, and smaller snow packs may indicate smaller spring floods. However, the increased winter rainfall may simply create an earlier flood season. These predictions feature in many studies (*e.g.* [54]).

A study of the potential change on the flood characteristics of the Thames and Severn rivers found both increasing flood frequency and magnitude as a result of the application of results from the HadCM2 GCM [127]. Three methods for altering rainfall characteristics were used to determine the flood effects: (1) proportional changes in rainfall volume, (2) alteration of the number of days in which rainfall occurred and (3) the use of an 'enhanced storm' procedure which intensified the high rainfall events. The flood peaks increased for all three methods but especially for the storm procedure. Overall, the magnitude of the fifty year flood was expected to increase by 20% and 15% for the Severn and Thames respectively.

While it is difficult to prove beyond reasonable doubt that the recent flooding in England and Wales was linked to climate change, such events could well become more common.

4.4 Implications For Water Resources and Hydropower

Climate change is anticipated to have serious implications for water resource availability and use. It is expected to increase water demand for agricultural and municipal purposes, alter navigation potential and affect recreational and fisheries usage [128]. For the purposes of this study the potential changes in river flows and their effect on hydropower production will be examined in detail.

4.4.1 Hydropower Potential

Water has been used to generate power for many thousands of years, originally in the form of water-wheels used to grind cereals, and later, during the Industrial Revolution to drive textile mills. Over the past century its main use has been to produce electricity, by passing the water through turbine-generators. Hydro now accounts for around 20% of world electricity production [53], and as Chapter 3 indicated its absolute energy contribution is expected to increase threefold by the end of the century [74].

The hydroelectric potential energy (E, J) is given by the volume of water (Q, m^3) falling through a vertical distance often referred to as the hydraulic head (H, m) according to:

$$E = \varrho g H Q \tag{4.1}$$

where ϱ the density of water (1,000 kg/m^3) and g the acceleration due to gravity (9.81 m/s^2).

Power can be generated by allowing water to flow through the turbines, as with run-of-river schemes (RoR), but there are benefits to the construction of a dam. Increased storage reduces variability, which allows more of the water to be used to generate power than in RoR schemes. Foot-of-dam generating stations allow an increased head which enables larger power output, and while this effect is also true for installations involving long penstocks, it is of a lesser extent. Design of hydro installations is generally based on the river flow duration curve which determines the type and capacity of turbines. Reservoirs are normally designed to provide a dependable flow of energy, by providing carry-over storage between seasons of high and low flows. The necessary storage is determined from mass-curve analysis for target levels of reliability [129].

Reservoir-based hydropower schemes are generally built to satisfy other requirements in addition to energy production. For example, the Hoover Dam on the Colorado River, was built in the 1920s to provide drinking and irrigation water to the arid south-west US, and the Three Gorges project on the Yangtze River in China is being constructed primarily to alleviate the devastating flooding that periodically affects the region [130]. The trade-off required to satisfy each purpose means that the reservoirs are operated in a manner that is non-optimal from the point of view of energy production alone.

Climate change has two primary effects on hydroelectric potential. Firstly, alteration of the flow distribution will affect power potential, although the impact on schemes with storage is influenced by the degree of storage available. The second effect is the increase in reservoir evaporation rates which will remove water before it can be used for generation.

River Flows

The limited hydraulic head in run-of-river plant implies that hydropower potential is linearly dependent on river flow. However, changes in the frequency of flows that lie outside the capabilities of the installed turbines means that there may be more occasions when the plant cannot generate because of low flows, or alternatively cannot take advantage of higher than rated flows.

For schemes with impoundments, generation potential is governed by the operating procedures of the reservoir. These are generally based on rules that relate the allowable release through the turbines to the current storage, and/or current or predicted inflows. Many are developed using stochastic techniques that account for expected variations in flow. However, changes in the volume and timing of river flows, as a result of climate change, may render the operating rules sub-optimal consequently lowering production levels.

An example would be the scenario of a rainfall shift from summer to winter with an overall increase in rainfall. Insufficient storage would force spillage of much of the extra winter flows preventing carry over to augment the low summer flows. In this case, the overall hydroelectric production would be likely to decrease. Similar results have been reported for water supply reservoirs: for some UK reservoirs altered climate was found to reduce the water yield (or volume supplied) by 8-15%, or alternatively require storage increases of 10-21% to maintain current yield [131].

The requirement for flood control storage tends to complicate hydropower analysis, but if increased winter flows imply a greater risk of flooding, it is likely that additional flood control storage will be allocated, reducing the available storage. This has the effect of reducing the reservoir level, the head available for generation and consequently the hydroelectric potential as the energy density of the water falls.

Reservoir Evaporation

Given that hydropower reservoirs are some of the worlds largest lakes, there can often be considerable evaporation from them. Despite this, it is quite common for evaporation losses to be ignored in many reservoir studies, or alternatively, assumed that evaporation net of precipitation is zero. Given that evaporation from open water is generally at or close to potential evaporation levels then more studies of the impact are necessary.

4.4.2 Power Production

A relatively small proportion of the literature concerning climate impacts on water resources deal with hydroelectric power production. However, in general, hydropower production tends to follow changes in runoff. For example, the application of three GCM scenario to the Nile river indicated very different changes in runoff and production [114]. The UKMO scenario lowered runoff by 12%, forcing production to decline by 21%, while the wetter conditions predicted by the GISS model increased both river flow and power production by around 27%. The GFDL scenario resulted in an extreme 77% fall in runoff which reduced power production by over 94%. Other rivers and regions are forecast to experience similar changes in power production (Table 4.3).

Region/River	Scenario	Energy Impact
Scandinavia [54]	GCM	+2-6%
Zambezi [114]	GCM	Dry Season: -18%
California [132]	ΔP -20%	Winter: -50%
Upper Colorado [133]	ΔP -20%	-49%
Lower Colorado [133]	ΔP -20%	-65%

Table 4.3: Examples of change in energy production due to GCM scenarios and arbitrary changes in precipitation (ΔP)

While climate change appears to have a detrimental effect on power production in many areas, the projections are that Scandinavian hydropower potential will increase slightly [54]. Most areas in the Nordel region could experience increases in runoff of up to 5% for a period around 2030, and up to 15% increase by 2100. Overall, the system potential increases by 2 and 6% respectively. The simulated annual production increase is of similar magnitude, rising from 188 TWh to 192 TWh. In most of the basins studied, winter runoff increased, spring snowmelt was earlier and lower and summer and autumn flows were reduced. The increased winter flows and reduced spring reservoir spillage are responsible for the increase in power production.

An assessment using the World Bank Indus Basin model found that the GCM scenarios applied indicated increased precipitation of 10-20%, resulting in an 11-16% rise in runoff and consequently a 19-22% rise in hydropower production [114]. A uniform 20% decrease in precipitation resulted in 17% lower production.

Another study on behalf of the US EPA found that power production in the upper and lower sections of the Colorado basin exhibited different sensitivities to precipitation [133]. For the upper basin (above Lake Powell) the power production declines to a lesser degree than the average storage, and a 10% fall in precipitation leads to a 15% decrease in runoff. This results in 30% lower storage and 26% lower production. In the lower basin, a 10% reduction in precipitation causes a 12% fall in runoff, which lowers storage volumes by 30% and hydropower production by 36%. The limited power storage in Lake Mead (held back by the Hoover Dam) is cited as the reason for the increased sensitivity of power production to changes in runoff, as the degree to which the the reservoir can be drawn down to meet demand is restricted. These examples indicate that it is not only the hydrological characteristics of the catchment that determine the sensitivity of hydroelectric power production, but also the features of the generating facilities themselves, and the robustness of the operating procedures. The apparent difference in sensitivity between scenarios of increased or reduced precipitation levels are related to the ability of the operating procedures to maintain power levels as well as take advantage of additional flows.

The vulnerability of water resource systems to changes in climate is one area that has attracted much attention. Most commonly, the system vulnerability is given in terms of how frequently generation fails to meet a target of some description. For example, the risk of not meeting predefined energy targets was examined for the Polyfyto scheme in central Greece [134]. For each of the GCM scenarios applied, the risk of failure in generating the mean annual guaranteed energy of 515 GWh increased. Conditions projected for 2050 by the equilibrium UKMO model found that risk increased from 1.3% to over 16%, and the transient scenario predicted an increased risk of 25% by 2080. An increase in storage of 20-30% was found to mitigate the risk.

4.4.3 System Operations

All electricity systems exhibit some degree of seasonal demand variation. In warmer climates the peak demand tends to occur in summer months, and the opposite occurs in colder regions. Most studies indicate significant seasonal changes in hydro energy production and this could have implications for the ability of electricity systems to meet demand.

In Scandinavia peak load is dominated by heating requirements over the winter months. Given that currently Norway sources over 97% of its electricity from hydropower, reductions in hydro energy production could limit the ability to meet demand. The projections presented earlier suggest that winter production will increase, which will be beneficial as it coincides with peak demand. A further benefit would be the lowering of the peak demand as temperatures rise [54].

A supply-demand study of the New Zealand hydro sector suggested major changes in the availability and consumption of electricity [99]. Currently, hydro production is lowest in winter, when demand is highest. However, for a 10% precipitation increase accompanying a 2°C temperature rise, annual runoff would rise by 12% and increase hydro potential by 1,700 GWh. Together with a fall in demand of over 4% the annual energy mismatch would be reduced by 2,800 GWh, requiring less reliance on other generation sources. A second scenario with a 10% fall in precipitation resulted in similar potential production during the winter months but a large fall in summer potential caused by a 68% reduction in runoff. The rise in temperature appears to benefit the country by reducing the winter snowpack volumes and allowing its use during the peak demand period.

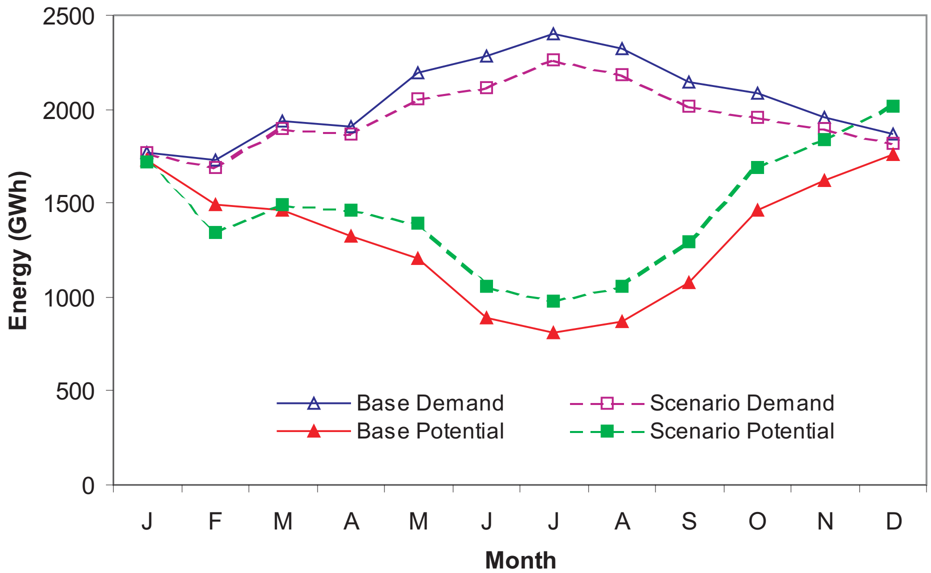


Figure 4.5: Mean monthly hydro potential energy production and consumption in New Zealand. (Scenario $\Delta P + 20, \Delta T + 2°C$) [99]

Robinson examined hydropower availability for several catchments in the eastern US [98]. Reservoir drawdown was used to indicate the potential to meet a proportion of temperature sensitive energy demands. It was found that drawdown was sensitive to the timing of dry periods, and that the most severe depletions occurred during summer hot dry spells. For a uniform 10% fall in precipitation and a 2°C rise, the minimum reservoir level fell by 50% although the decline was normally in the region of 9-17%. No analysis on the impact of such changes on energy production was provided.

A similar study was carried out for the Grande Dixence scheme in Switzerland [135]. The glacier dominated runoff is greatest in the spring and summer, and under conditions predicted by the UKMO GCM annual runoff would increase by 35%, although most this would arrive in the summer. This raises the reservoir level significantly and leads to significant spillage, as the reduced summer load (and the assumption of supplying a fixed proportion of demand) prevents its conversion into energy.

Changes in hydroelectric potential will vary geographically It is possible that changes in the energy potential of hydro schemes, coupled with weather sensitive demand, will lead to non-optimal use of generation, as transmission and dispatch constraints prevent merit order scheduling.

4.4.4 Economic Impacts

The precise impact of changes in hydropower energy production will depend very much on the market situation. At the basic level it implies changes in electricity sales and therefore project income. In addition the utility may have to generate replacement energy, and where this involves additional fuel use or purchases from other parties this will incur costs.

Revenue

In a cost-benefit analysis of a cascade of hydro reservoirs on the Mekong, Reibsame *et al* found that for the GCM scenarios applied (which indicated reduced flows), the benefits from power production were lowered by around $1 billion [114]. An alternative case with a 20% increase in precipitation created an additional $10 billion of benefits.

The optimal design for a hydroelectric scheme in Quebec, Canada was found to alter with climatic change [136]. Using a least cost criterion, changes in river flows increased the marginal costs of the scheme and reduced the guaranteed or 'firm' energy production.

Whittington and Gundry note that although revenue will tend to follow changes in production, there will be little effect on the predominantly fixed capital and operational expenses [137]. As such, these costs will have to be met from the possibly reduced revenue stream. For existing installations, revenue lower than expected will result in lower profit, and if the changes are sufficiently severe an operating loss. Sustained losses would risk the financial future of the operation, as its capacity to cover debt servicing costs will be reduced, although the scheme could continue to run for strategic reasons.

The possibility of reduced profitability may have a more serious impact on proposed hydropower schemes. Hydropower developers will have to alter their estimates of runoff used in project appraisal, and it is possible that proposed schemes will not proceed, or will be altered in some manner [137].

Replacement Energy

To avoid demand curtailment, lost hydroelectric production must be replaced either by increasing output from other plant or by importing energy via inter-connectors. These actions impose additional costs on the system, particularly if the losses occur during peak-load periods. In liberalised markets, hydro generators may have to purchase energy from other players to secure any shortfall.

Reductions in hydropower potential in northern California were found to significantly affect the operating costs of the Pacific Gas and Electricity Company [138]. One scenario saw annual production fall by nearly 4%, and by 20% during the peak-load summer months. The loss of hydro potential required additional natural gas use costing $145 million (1993 prices) increasing annual system costs by 12.5%.

Reibsame *et al* examined the impact of altered climate on the cost of replacement energy in the Uruguay River hydro system [114]. Two GCM scenarios indicated that annual energy production would fall relative to the base case by around 486-1,800 GWh per year. The authors noted that to make up the shortfall could require an additional 375 MW of plant capacity, costing in the region of $375 million. An alternative scenario implied a 22% increase in runoff resulting in an additional 4,850 GWh/yr of production and yielding an additional $1 billion in revenue. However, the lack of a detailed systems simulation prevented the estimation of spillage and therefore there was uncertainty regarding power (and revenue) losses.

4.5 Research Analysis

The previous sections in this chapter have covered the broad range of potential impacts of climate change on river flows, hydropower production, system operation and to a limited degree the economics of hydropower schemes. While these impacts are important they do not allow a full consideration of the research hypothesis. This section examines the limitations in previous studies, before considering the primary study focus on hydropower investment which allows the hypothesis to be addressed. Finally, the potential impact of changes in hydropower investment levels will be examined.

4.5.1 Limitations of Existing Studies

There are a number of key limitations with studies of climate change impacts on hydrology and hydropower.

Scenarios

The many different scenarios used to assess hydrological impacts creates difficulties for comparing studies. The hypothetical changes are simpler to compare, but they are unlikely to provide a realistic scenario of future conditions. The uncertainty surrounding the projected impacts is an important consideration. The current state of hydrological and hydropower operations modelling implies that their contribution to overall uncertainty is minor, dominated as it is by the results of the global circulation models.

Hydrological Models

It is important to take care when comparing the results of hydrological studies. Hydrological studies use different models of varying complexity which results in a wide variation of sensitivity to climate variables and in particular, changes in variables [139]. Some may not be suitable for the type of climate, and accurate reproduction of current river flow regimes does not necessarily imply accurate prediction of future flows, although careful statistical analysis can reduce the risk [107].

Many models require estimates of potential evapotranspiration, applied directly as an input or calculated using one of the many methods available. Methods differ in their complexity, data requirements and performance in specific climates. The result is that estimates differ considerably for current and future climates, and those with a sound physical basis are recommended [140].

Hydropower Representation

For studies involving hydropower several limitations are apparent, particularly with respect to the modelling of reservoir operations and hydropower production. The assumption of a fixed hydraulic head or the failure to account for spillage leads to over-estimates of power production. The future validity of statistical relationships between historic hydro production and river flow (*e.g.* [132]), or the assumption of zero net evaporation are questionable. The use of non-standard terminology relating to energy potential (*e.g.* [98, 135]), makes comparisons difficult. As with the hydrological models, the plethora of reservoir models makes direct comparison difficult.

Study Scope

Climate change is expected to have impacts on three aspects of renewable energy provision: the availability of the resource, its operational performance and the 'willingness to develop' resources [102]. Most of the research to date has been concerned with assessing the potential impacts on the hydroelectric resource; fewer still have considered the operational performance of schemes; and while the question of willingness to develop has been addressed qualitatively by Whittington and Gundry [137], there has been no quantitative analysis.

4.5.2 Study Focus on Hydropower Investment

A more complete picture of the impact of climate change on hydropower will be gained by a quantitative analysis of the effects on the 'willingness to develop'. The analysis will be improved if the shortcomings of previous studies can be addressed, by for example, the use of physically sound hydrological models and operationally accurate reservoir models.

'Willingness to develop' will now be defined and the factors that currently influence it will be examined. The potential effects of climatic change on willingness will then be assessed in a qualitative manner.

'Willingness to Develop'

'Willingness to develop' could be considered as the desire to expend human and financial capital in the pursuit of particular goals, in other words the attractiveness of investment in a project. The goals could be the universal supply of electricity, avoidance of environmental damage, achieving a financial return or a combination of all three and others. The decision as to whether an electricity generation scheme represents an attractive investment depends partly on the goals of the investor and partly on alternative opportunities. The likely alternative to hydropower projects is fossil-fuelled plant, and so comparisons will be made in a number of areas. Some of the important issues are summarised in Table 4.4.

Positive	Negative
Long lifetime	Long payback period
Renewable resource	Hydrological risk
No fuel costs	High capital costs
No fuel/import price risk	Exchange rate risk
Few emissions	Community relocation
Operational characteristics	

Table 4.4: Positive and negative aspects of hydroelectric developments

The most important consideration is the ability of the installation to recoup capital costs from its revenue stream. This is true for market economies, particularly in light of the increasing contribution of private capital in the ESI (illustrated in Chapter 3). In the past it may have been less so for developing countries or those with command economies, where schemes have been justified on strategic or political grounds [141].

The high capital cost of hydropower schemes tends to disadvantage them relative to fossil-fuelled plant. This is apparent as the standard technique of comparing different technologies considers their discounted unit energy cost [142]:

$$Cost = \sum_{t=0}^{n} \frac{I_t + M_t + F_t}{(1+d)^t} / \sum_{t=0}^{n} \frac{E_t}{(1+d)^t} \tag{4.2}$$

where d is the discount rate, E_t is energy production and (I_t), (M_t) and (F_t) are the costs of investment, operations and maintenance and fuel, respectively.

Although hydro has no fuel costs and therefore is not susceptible to changes in fuel (and import) prices, the calculation weights the capital cost more than recurrent fuel costs and therefore biases the analysis in favour of the lower capital cost technologies. This is especially true if high discount rates, consistent with higher-risk liberalised industries, are used. It also ignores the long lifetime, and the fact that electricity costs reduce to virtually zero once the capital is repaid. Another difficulty is that many of the most economic sites have already been developed, implying more costly schemes in the future. For example, new capacity built in in developing countries during the 1990s was estimated to have cost around 7.8 US cents per kWh [143], well above historically low hydro costs.

Climate change will alter the energy estimates used for the calculation and could increase the unit cost. In instances where generation investment is determined on a least cost basis this could force a change in the investment plan. For more liberalised systems, investment will be based on projections of future revenue, and profitability, both of which could be adversely affected by climate change. It is possible that in some cases investment will not proceed, and this will have impacts of both regional and global nature.

Regional Impacts

The abandonment or reduction in capacity of hydro schemes would have a number of important impacts. Firstly, an alternative source of energy would be required, and if fossil fuels are used, then this implies an increase in the carbon burden. Secondly, the balance of payments of the host country would deteriorate if fuel importation was necessary. Finally, it is possible that the transmission network would have to be reinforced [137]. These impacts imply additional costs, particularly over the long term.

Alternatively, if the effects of climatic change are not included in the investment decision, then the impact could be equally serious. Large dam projects have contributed to the debt burden of many developing countries. The high capital cost prevents purely domestic financing, and the long term loans from international institutions require repayment in hard currency, exposing the relatively weak economies to long term currency risk. Exchange rate shifts have reduced or prevented repayment of the loans from electricity sales revenue. Reductions in revenue due to climatic changes would increase the length of time for financial break-even, possibly to such an extent that the scheme never does. This will make the debt problem more serious.

International Impacts

These effects are not just a problem for the host country, but for the international community too. Overall, the resources for financing investment in energy are limited, and so an investment rendered sub-optimal by climate change represents an opportunity cost to society as a whole. The debt burden is not just a problem for those suffering from it, but also to the rest of the globe.

One of the ways of developing hydropower is through investment by foreign companies. The Clean Development Mechanism (CDM) of the Kyoto Protocol will allow these companies and hence their host countries to claim carbon credits to set off against their emissions. Lower production than expected would lower the carbon credits available to the investor, effective increasing the cost per unit of CO_2 avoided.

As hydropower is one of the methods of easing the carbon dioxide problem, abandonment of potential schemes or reductions in production will tend to reinforce global warming (Figure 4.6).

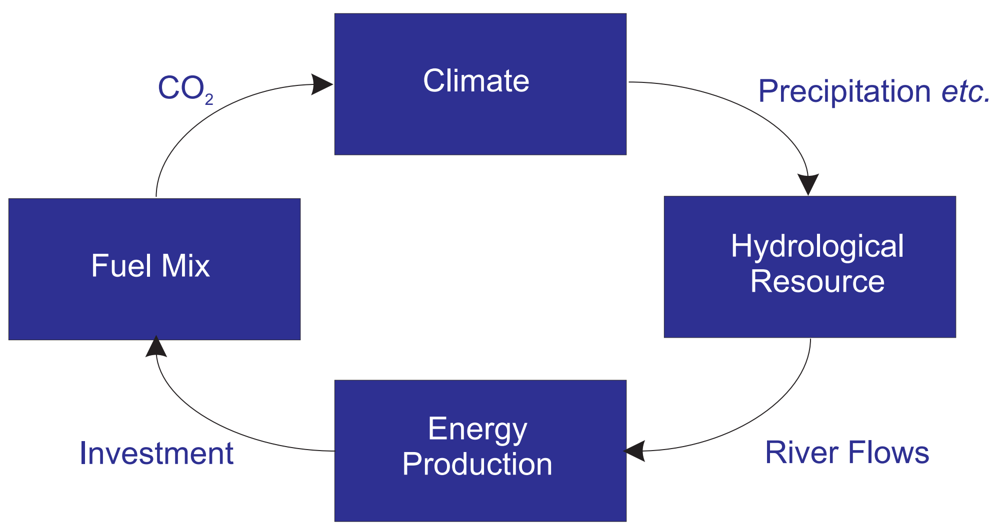


Figure 4.6: Climate feedback through hydroelectric energy resources

4.6 Investment Appraisal

In order to provide the basis for a quantitative analysis of the impact of climatic change on investment, it is necessary to detail how feasibility studies currently appraise projects.

4.6.1 Feasibility Studies

The standard feasibility study considers many aspects of the potential scheme: technical, engineering, economic, and environmental. However, it is the financial appraisal that is most important for the project sponsors, investors and lenders, and it aims to provide information that allows the parties to the scheme to determine if it will be able to repay the debt incurred and provide a suitable return.

For electricity generation projects, likely energy output and revenue is assessed and compared with capital and operation and maintenance costs over the planned lifetime of the plant. Hydropower appraisal is slightly different in that its fuel source is not guaranteed, and therefore focuses on the availability of the water resource, through an examination of historic river flows at the site in question. Whilst the plant is designed on the basis of the river flow-exceedance probabilities, estimates of output are determined by a time series simulation of the plant with assumed operating procedure defining the output. Using pricing information relevant to the current or likely future market structure, revenue can be estimated, and various measures can be used to determine the likely financial health of the project. Figure 4.7 illustrates the process schematically.

Available river flow data is traditionally assumed to contain most of the hydrological variability of the catchment, including periods of drought. Project vulnerability to drought conditions can be assessed by applying a sequence of historic river flow data that contains the 'critical' period. Improved analyses use synthetic flow data to determine the robustness of the project to differing sequences of river flows. The synthetic flow data can be created by the use of Markov models, which use the regression relationships between seasonal flows [144].

4.6.2 Appraisal Measures

There are a number of different calculations used in the economic appraisal of projects including hydropower schemes.

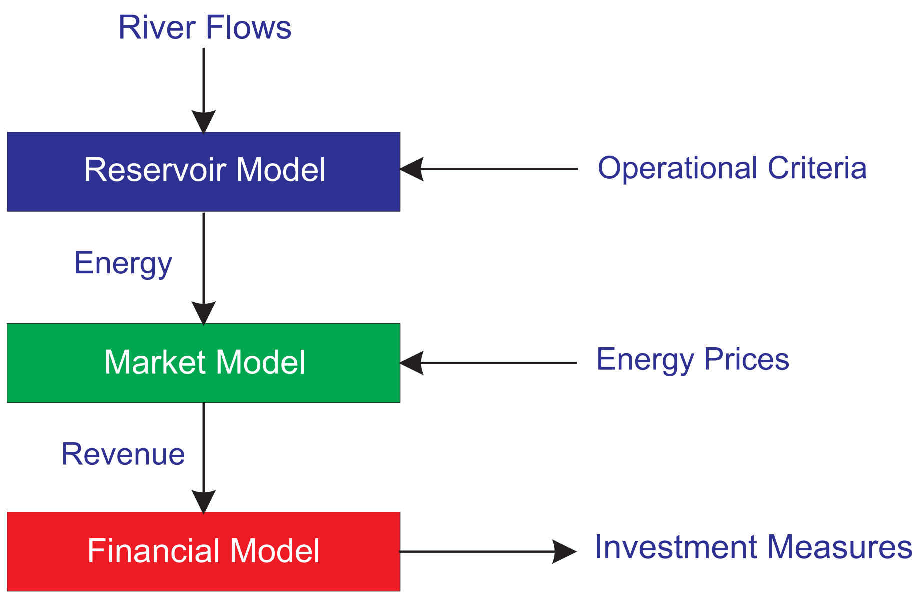


Figure 4.7: Standard financial appraisal for hydropower schemes

Simple Measures

'Payback' measures the length of time expected to recover the original costs of a project. It is often used as a screening method to eliminate proposals with unacceptably long payback periods. However, it ignores the fact that some projects take inherently longer than others, and therefore is an arbitrary means of decision making. It ignores the cash flows after the payback time and can result in perverse choices. It also ignores the value of the money over time. Often payback is considered as a proxy for risk, in that it can be preferable to recover costs in the shortest period of time. However, projects with short payback times may in fact be more risky as high rates of return are generally associated with increased risk [145].

The return on investment (ROI) method is another relatively simple calculation used. Alternatively known as return on capital employed (ROCE) it represents an average rate of return determined from average profit and average capital employed, and generally uses profit after depreciation. Projects tend to be selected on the basis of higher ROI values. It is simple to apply and is useful where management is judged on the overall company ROCE. Although it takes account of cashflows after the point of payback, there are numerous methods of defining ROI, and it does not differentiate between the size of investment decisions.

Payback and ROI are frequently used to assess investment opportunities. Their simplicity is advantageous but can produce misleading results as they ignore the timing of cashflows.

Discounting Methods

The previous measures are limited by the fact that they do not take account of the time value of money. The preference can attributed to a number of factors: that investing money now will allow it to appreciate; that consumption is preferred now rather than later; the erosion of purchasing power by inflation; and given the chance of misfortune over time it is better to have the money now. In many ways the rate at which money loses value, the 'discount rate', reflects the perception of risk. As such, investments sponsored by government attract a lower, or 'social', discount rate than private projects. The theory of discounting is useful in assessing long term capital projects through several methods: discounted payback which uses discounted cashflows; net present value analysis and internal rate of return analysis.

The net present value (NPV) of a project is the difference between the costs and the worth of a project. It is the present value of all cash flows (CF) connected with the project discounted at rate reflecting the accepted discount rate (d), and the project is deemed acceptable if the NPV is positive:

$$\text{NPV} = \sum_{t=0}^{n} \frac{CF_t}{(1+d)^t} \tag{4.3}$$

The internal rate of return (IRR) is the discount rate that would deliver a NPV of zero. The project will be accepted if the IRR exceeds the project's cost of capital.

Although the NPV and IRR analyses appear to be the same there are differences between their results. The IRR is often favoured as it is rather intuitive and avoids the need to preselect a a project minimum acceptable rate of return. The methods agree when projects are independent and conventional: independent in the sense of not precluding another, and having a conventional cash flow profile of net cash outflow, followed by net inflows. It is possible for a project to have more than one IRR, reflecting the reversal in sign of net cash flows, and the choice of the correct one can be problematic [146]. Overall, the net present value is the more robust method to follow [145].

Annual Coverage Tests

In addition to measures that assess the overall worth of projects a number of measures are used to indicate financial performance over time. As well as numerous profit measures and liquidity ratios commonly used by accountants, lenders commonly rely on two indicators to gauge the capacity of a project to support debt [147].

The 'interest coverage ratio' expressed as the ratio of profit and interest payments measures the project's ability to cover interest charges. The profit measure is normally earnings before interest and taxes (EBIT). An interest coverage ratio greater than one indicates that interest charges can be covered, however, to account for uncertain cash flows the threshold is often set higher (*e.g.* 1.25).

The 'debt service coverage ratio' includes the principal as well as the interest. Principal repayments are not tax-deductible so these must be made from after-tax profits. However, depreciation charges in the profit and loss account are available to repay the principal. Debt can be fully serviced when the ratio is greater than one, otherwise borrowing or equity contributions will be required to cover the difference. Again a margin of security is often required.

4.6.3 Risk and Return

The discounting methods require a discount rate to allow assessment of project value, and the theoretical basis is outlined here. The discount rate is regarded as the rate that could be received from the most comparable alternative investment, in other words the opportunity cost. The rate is known as the firm's 'minimum acceptable rate of return' (MARR), and a project will only be accepted if it provides a return equal to or greater than this rate. In the absence of a comparable opportunity it is possible to determine the required rate of return from an examination of the capital structure of the project.

The discount rate can be calculated from the firm's weighted average cost of capital (WACC). WACC is the average of both debt and equity rates of return weighted by their contribution to the capital of the company:

$$\text{WACC} = (1-\theta)c_e + \theta(1-\tau)c_d \tag{4.4}$$

where c_d, c_e are the costs of debt and equity, θ the proportion of debt and τ the marginal tax rate.

The debt and equity rates are estimated in different ways. The cost of debt is simply the interest rate at which lending can be secured. However, the difficulty lies in estimating the the cost of equity. Debt involves payment obligations and often involves claim over assets, but equity does not. The equity purchaser will only purchase a risky asset if they expect a rate of return that compensates for this risk, with the expected return increasing with risk.

Projects or companies have two components to their risk profile: 'systematic risk', shared by all market participants, and 'specific risk', particular to the entity. The assumption is that a rational investor will minimise their exposure to the specific risk, and as such do not require rewarding for it. Accordingly it is the systematic risk that determines the required rate of return to be paid by the company.

Capital markets provide a standard in measuring the trade-off between expected return and risk. The return provided by default-free government bonds is regarded as risk-free. The market itself has an expected return given by the mean return of a portfolio of all stocks in equal proportion, and its risk is measured by its standard deviation. This risk is regarded as the standard systematic risk of an individual security. The relative risk of a particular security compared to the market risk is termed its beta (β_e) coefficient. A beta of 1 means that the security carries the same risk as the market, while beta's greater than or less than one indicate a more or less risky investment respectively. Betas tend to range between 0.75 and 1.5.

The relationship between risk and return can be determined by the application of the capital asset pricing model (CAPM), which states that assets with the same risk should have the same rate of return. The CAPM states that the expected rate of return on a portfolio should exceed the risk free rate by an amount proportional to the beta coefficient of the portfolio. For a single security this gives

$$r_e = r_f + \beta_e(r_m - r_f) \tag{4.5}$$

where r_f, r_m and r_e are the risk-free, market and individual equity rates of return.

4.6.4 Implications of Climate Change

The preceding sections detail the process of the traditional feasibility study, some of the economic measures used, and how project risk and return are linked. However, the prospect of climatic change necessitates that a number of factors require re-examination.

Appraisal Process Adjustments

Potential climate change suggests that past river flows can no longer be relied upon to indicate future flows, implying that the traditional investment appraisal is inadequate and must be altered. Relatively recent studies do not take account of it. For example, the Three Gorges study was published in 1988, only two years before the IPCC First Assessment, but it contained no reference to climatic change. However, some studies are beginning to take account of climate change but it appears to be only in a very rudimentary manner, for example by reducing river flows by 10% for public schemes, or a more conservative 20% for commercial projects [148]. Unfortunately, simply altering river flows in a uniform fashion does not take account of the complex interactions between precipitation and evapotranspiration, and therefore may ignore the precipitation amplification effect or seasonal changes.

The requirement therefore is to remove the reliance on historic river flows in favour of the use of climatic variables that ultimately determine river flow.

Increased Risk

The economic viability of a scheme depends on the cost of capital and this can be altered by climate change. Although the market equity rate is unlikely to be affected by climate change alone, the equity beta reflects the risk and so it will tend to increase the required rate of return for the equity. With project finance, the majority of the capital is in the form of debt so the effect on debt cost is important. The lender will determine the lending rate based on their assessment of the risk of not receiving the money back. An increased risk (*i.e.* hydrological risk) will tend to increase the lending rate to compensate.

The increased cost of capital will alter the discount rate used, and possibly render the project as unsuitable for investment. At the very least it will make hydropower less attractive than other generation methods. It is uncertain how great this (secondary) effect will be, and therefore it must be examined through the assessment of future river flows.

4.7 Summary

This chapter details the impact of climatic changes on the hydrological cycle and in particular on river flows. The resultant effects on hydropower potential, and operation are also detailed. Limitations of existing studies in the literature are highlighted and a proposal made to examine quantitatively, the impact on investment in hydroelectric power. Current methods of investment appraisal are noted and suggestions made as to their limitations in light of climatic change.

The key questions to be answered are:

1. What impact will climate change have on the financial performance and risk of hydro schemes?
2. How will this affect the terms for financing and the financial returns deemed acceptable by investors?
3. What will be the knock-on impact on the provision of hydropower worldwide and the ability to meet carbon emission targets?

Chapter 5

Modelling Change

This chapter defines the specifications for a piece of software suitable for analysis of the impact of climate change on hydropower investment. The methodologies required to quantify changes in the economic feasibility of hydropower schemes are then examined, different approaches are investigated and recommendations made.

5.1 Objectives

The previous chapter indicated the need to examine the impact of climatic change on three key areas. The first aspect requires analysis of the effect of change on a range of measures used to determine investment suitability, while removing the current reliance on historic river flow patterns. The second and third aspects follow directly from this.

5.1.1 Analysis Methodology

Estimates of the impact of climatic change may be gathered from climate change impact assessments. To be useful they must be based on a rigorous, well-documented methodology and each stage must be credible and scientifically supportable [149, 150]. They follow one of three possible methods: *impact* assessments are generally the least complex and model the cause and effect of a specified change; the *interactive* approach includes the effect of feedbacks and other non-climate changes; finally, the *integrated* approach examines the interactions of different sectors of society under changing climates, and models developed for this purpose are called 'Integrated Assessment Models'. For this application, the primary need is to examine the effect of changes in climate on financial performance suggesting that the study is an impact study. However, the extrapolation of the analysis to attitudes and requirements of investment, means that overall, the study could be described as both an impact and interactive assessment.

Analysis of the impact on hydropower financial performance is limited in scope to individual hydropower schemes rather than entire systems (as was the implicit focus of the last chapter). There are a number of reasons for this: time constraints, the need to gain an in-depth understanding of the processes at work, and the heterogeneous nature of hydropower schemes. The nature of the analysis necessitated the selection or development of suitable software in order to provide a means of rapidly assessing scheme sensitivity to climate change and to allow examination of its impacts. The software would be used to allow an initial inspection of individual schemes, to indicate whether the issue requires closer consideration.

The basic goal of the prototype software is to facilitate academic consideration of the issues surrounding climatic change, although further development has not been ruled out. Ideally, the software would be able to cope with any hydropower scheme or system, but due to the large variety evident in existing or planned hydropower schemes, a number of restrictions were necessary to limit the magnitude of the task. Firstly, that schemes should consist of a single reservoir with limited or no upstream regulation in order to avoid problems with the coordination of cascaded systems. Secondly that power generation should be a major aim of the scheme, to simplify the project economics. Despite these restrictions this should allow most schemes worldwide to be successfully modelled.

To satisfy the first key research question, the software has to perform a financial appraisal of the given scheme. The key difference with the traditional approach is the replacement of river flow by climate information as the primary data source. To facilitate this, a hydrological model forms the bridge between climate and river flow. The effect of this additional component on the appraisal structure is shown schematically in Figure 5.1.

5.1.2 Software Considerations

The key requirement was that the software should encapsulate the entire financial appraisal process or at the very least a significant portion of it. This arises from the need to perform the financial analysis quickly and efficiently, with a minimum of external data transfer. A thorough examination of available commercial and academic software concluded that none could be applied generally or featured most or all the necessary components. Integrated software models of large river basins that could simulate much of the process do exist (*e.g.* Indus [114]), but would not be suitable for transfer to other river basins.

The possibility of connecting separate pieces of software to create a coherent unit was also investigated. The advent of the Microsoft Windows component object model

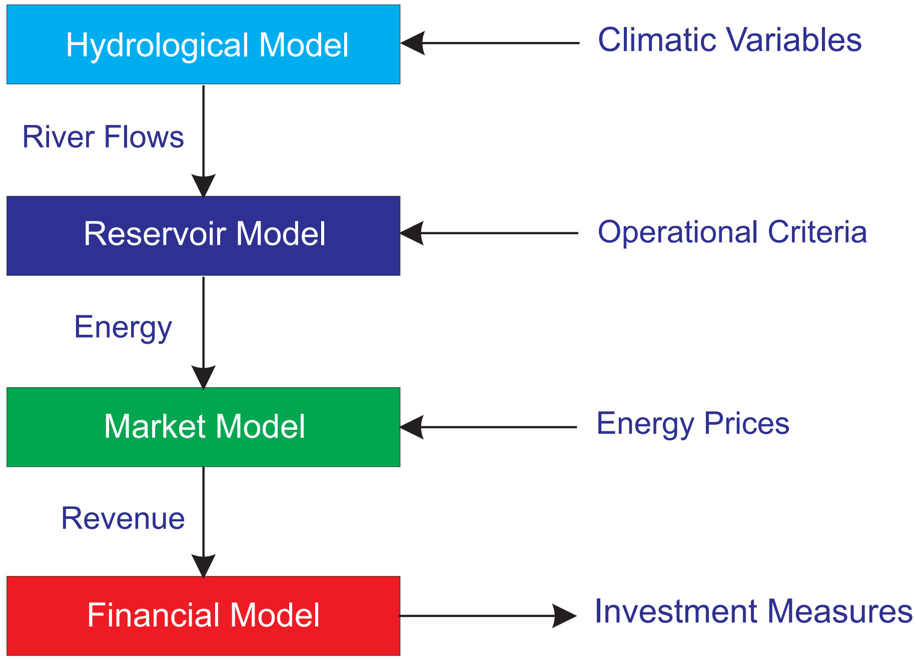


Figure 5.1: Financial appraisal for hydropower schemes adapted for climate change

(COM) has made the process simpler and allows particular pieces to be controlled by others. However, the variety of platforms used and other compatibility problems suggested that some software models would have to be rewritten, and as such it was deemed more effective to produce a single piece of bespoke software. Additional benefits of a stand-alone package would include control over software operation and scope. Some of the software models examined are detailed in the next section.

5.2 Available Modelling Methodologies

In this section, the constituent parts of the new feasibility study model are examined in terms of possible approaches and their suitability for the current purpose.

5.2.1 Climate Change Scenarios

Impact studies aim to provide a comparison between conditions with and without climate change. Other than a 'baseline' scenario representing a specific (and usually current) period of time, scenarios of plausible future climate conditions are required. There are several distinct methods for doing this:

Arbitrary Scenarios

Specified and arbitrary (or hypothetical) changes in climate can be used to either investigate the implications of change or examine the sensitivity of a hydrological system. The method is useful in assessing the vulnerability of catchments or water resources systems to changes in climate inputs, but is not useful for estimating future conditions [107]. As the preceding chapter notes, the majority of studies fall into this category.

Analogue Techniques

It is possible to define scenarios based on temporal or spatial analogues. Temporal analogues use information from historic periods to provide an illustration of, for example, a warmer period. Information can be gained directly from instrumental records or from palaeoclimatic reconstruction, but both methods are limited in their application. The instrumental approach relies on the assumption that differences between historic warm and cool periods are a good analogue for warming under climate change. This may not be the case as the causes are different, particularly if past differences are due to random fluctuations. Other issues include the short record length, and perhaps an insufficiently large temperature difference between the analogue periods. Despite these, historic information may be useful for examining how systems fare under extreme conditions. The use of paleoclimatic analogues is limited primarily by the fact that quantitative information is difficult to obtain. However, their major application appears to be in flood reconstruction or in indicating how the fluvial system responds to changes in climate [121].

Spatial analogues use the current climate of one location to represent the future in another. This often is unrealistic as climate is influenced by the local features such as the terrain. Hydrological information is even more difficult to transfer, as the characteristics of the catchment (*e.g.* geology) determine the regime. Accordingly, attempts to investigate future conditions in southern England using south-western France as an analogue failed because of this [151].

General Circulation Models

As examined in Chapter 2, the most effective method of estimating future climate is the use of General Circulation Models. Current GCMs not only simulate atmospheric variables, but through their land-surface models can simulate runoff. Therefore, the simplest method of determining changes in runoff is to use these values directly. Miller and Russell determined the change in annual runoff for over thirty major rivers directly from the GISS model [111], while the US Environmental Protection Agency (EPA) considered the runoff indicated by a range of models [112].

There are a number of reasons for the lack of suitability of this approach and problems associated with GCMs in general. Firstly, the land-surface models employed in the GCMs are very simple, and therefore unlikely to represent runoff in a physically sound manner. Secondly, regional climate is not particularly well simulated, as explained in Chapter 2. Finally, the spatial resolution of GCMs is presently too coarse for direct application to hydrological purposes, with the best GCMs operating at scales of 10^5 km^2, rather than the 10^3 km^2 required. This prevents the accurate representation of local or regionally important patterns. The temporal resolution of GCMs is in the order of minutes, and whilst this can be aggregated into daily time steps preferred for most hydrological purposes the spatial resolution prevents any meaningful use of the shorter time step data [107].

While these factors restrict the direct use of GCM output they can be used to create scenarios by using the climate data directly, or by applying the implied change to historic data. It is assumed that the GCM reliably simulates current climate, and that the indication of change is reliable, for the direct and change cases respectively. Applying changes to historic data ('perturbation') can be done by altering the historic data by the relevant amount, although this does not alter the temporal structure. Alternatively a stochastic weather generator can provide time series of climate variables based on the statistical properties of the variables [152]. This approach suffers because it is difficult to create a model that can correctly simulate climate and be able to alter the statistical properties. The second major consideration is how best to overcome the spatial scale problem.

Downscaling

Reduction of the spatial scale from the GCM to that useful for hydrological and other purposes requires the use of 'downscaling' techniques. The simplest approach is through interpolation either subjectively or using a statistical method, and values for each area are inferred from the larger-scale pattern [153].

Another method is to use circulation patterns or weather types by defining them to indicate surface conditions. This uses atmospheric pressure patterns to determine weather conditions, and this method is particularly suited to GCM application as they have been shown to reproduce pressure patterns very well. This method has been used in the assessment of future water resources in the Anglia Water region [154]. However, the method assumes that the empirical relationships between circulation type and local weather variables remains constant, which may not be the case.

The greatest potential appears to lie in the use of regional high resolution climate models embedded or 'nested' within the GCM. The GCM provides boundary conditions and the smaller model provides a more detailed simulation including terrain and coastline information. The indications are that such models produce more realistic simulations and suggest different climate changes than the driving GCM alone [155]. They are however, dependent on the quality of the larger GCM simulation.

Recommendations

It is apparent that analogue techniques are not suited to this application. While downscaling GCM output is likely to deliver improved hydrological representation, the necessary investment in time and resources is beyond the scope of this application. Moreover, it would contravene the requirement for 'simple' approaches. Otherwise, the use of GCM output, particularly the perturbation technique appears to be satisfactory, as does the use of uniform change scenarios.

5.2.2 Hydrological Models

Hydrological models convert climate inputs into runoff and other hydrological outputs, and are in use in water resources design, operation and forecasting. They have been proposed, developed and refined over many years, and the complexity of individual models tends to reflect the available knowledge and processing power [156]. This is reflected in Figure 5.2, which illustrates how variations in spatial and temporal characteristics influence model complexity. These factors will be considered in the following sections. The differing complexity of models allows them to be classified as empirical, process-based or conceptual [157], although other descriptions exist (*e.g.* see Todini [156]).

Empirical

Empirical models use statistical relationships to link climate variables and runoff. Most use regression techniques although many recent studies have examined the suitability of artificial neural networks (ANN) for modelling hydrological processes [159, 160]. Empirical models have been applied to predict long term average runoff and flood levels, and although they implicitly reflect the physical relationship between the dependent and independent variables, there are issues with their use. Model sensitivity is influenced by structure and the period used to develop the relationship. Comparisons between models have found that output varies significantly [161]. Additionally, the implied relationship may not apply to altered climates, and therefore the use of such models in conditions or locations different from that used for their generation is criticised [157].

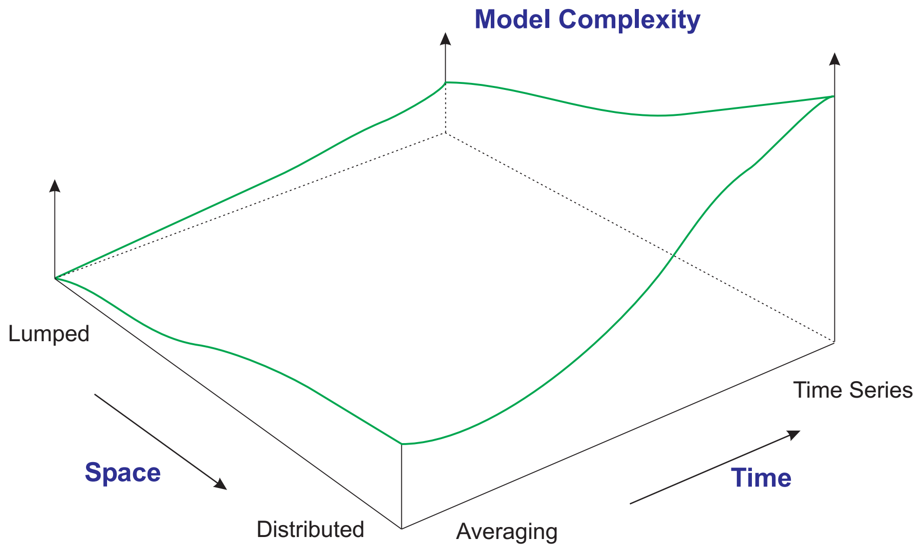


Figure 5.2: Influence of spatial and temporal characteristics on hydrological model complexity [158]

Process-Based

The most complex process-based models use physical laws to determine water flow in the catchment, and a growing number are available [157]. Normally spatially distributed, some operate down to the metre scale, and have a time step of minutes. The aim of such models is to determine the parameters based on measurements but in practice some of them are determined through calibration. Although they tend to produce realistic simulations of hydrological processes, their use in climate impact assessments has been limited. This is due to the large data requirement, and the requirement to define climate scenarios at very short time steps, which is not possible presently. There is also concern as to whether small-scale physical processes apply at the grid scales used in the models [162].

Conceptual

Conceptual models lie midway between the two previous types of hydrological model in terms of their ability to produce realistic simulations and of data intensity. They represent the catchment as a series of storage zones and describe water flows between them, and all employ some form of water balance approach to account for the flows. The capacity of each store and the parameters controlling the flows have some physical basis, and can sometimes be determined explicitly, but they mostly require calibration using historic stream flow data. The catchment can be represented as a single area or as a series, and this distinction refers to models as 'lumped' or 'distributed'. They can be operated on a variety of time scales, from monthly to hourly depending on the application, data availability and catchment size. As catchment size increases, short-term variations in runoff tend to be smoothed out, allowing more simple lumped models to suffice. However, simpler models tend to poorly account for storm runoff on shorter time scales [157]. Some of the better known models are listed in Table 5.1.

Model and Origin (if not US)	Type	Parameters
Stanford Watershed	Distributed	34
Sacramento	Lumped	17
Hydrocomp Simulation Program (HSP)	Distributed	-
USDAHL	Lumped	166
UBC (Canada)	Lumped	9
HBV (Sweden)	Distributed	-
HYYROM (UK)	Lumped	15

Table 5.1: Examples of conceptual hydrological models [157, 163]

The advantages of conceptual models have led to them being widely adopted in climate change impacts assessments. The Sacramento Soil Moisture Accounting Model has been used in a number of climate impact assessments in the United States [113, 120, 118], Greece [164] and elsewhere. Although the models shown in Table 5.1 tend to allow relatively detailed assessments of the magnitude and timing of hydrological response to climate changes, difficulties arise due to the large number of parameters that must be estimated or calibrated, as well as the quantity and variety of data required [157]. As a result a wide range of more simplistic water balance models have been developed and applied to the climate change problem.

Originally developed by Thornthwaite in 1948 [165], water balance models effectively account for the movement of water from the time it enters a catchment as precipitation until it leaves as runoff. Differences tend to be in detail rather than concept, with the main variations in the input data requirements, the nature and number of moisture storages, and the representation of hydrologic processes [166]. They have been applied on a range of time-scales from daily to annual time steps, but most climate studies have used a monthly step (*e.g.* [167, 117, 161]).

Hydrological Model Calibration

Despite the relatively simple nature of many conceptual models, there still exists a need to calibrate them, or rather to adjust their parameters such that simulated runoff closely matches the observed record. A large body of literature relates to the calibration of hydrological models. Many different types of techniques have been applied.

Exhaustive or blind search is one of the simplest methods, and searches until a solution is found. However, as the number of parameters requiring estimation increases, the search-space grows exponentially, as does the computational effort. A heuristic search provides direction and avoids sampling of the whole space, whilst larger numbers of parameters can be fitted with genetic algorithms (GA), which rely on the principles of Darwinian Evolution to select the optimum parameter set [168]. Other parameter estimation techniques have been summarised by Singh [169].

Calibration consists of selecting different parameter sets until the closest fit is found. The suitability of a particular parameter set is determined by the objective function which compares the river flow series simulated by the model to the observed series. The objective function can take many forms including many standard statistical measures (*e.g.* coefficient of determination, R^2). However, specific measures are often recommended with, for example, the American Society of Civil Engineers (ASCE) advising the use of the Nash-Sutcliffe efficiency criterion (NS) [170]:

$$\mathrm{NS} = 1 - \frac{\sum_{i=1}^{N}(O_i - S_i)^2}{\sum_{i=1}^{N}(O_i - \bar{O})^2} \tag{5.1}$$

where O_i and S_i are the observed and simulated flows and $\bar{O}$ is the observed mean flow. This measure tends to bias results towards high flows, so other methods, such as the use of the logarithms of flows may be more suitable [107].

Recommendations

Empirical models are precluded by their transferability issues, while process-based models are ruled out through excessive data requirements. Within the ranks of the alternative, water balance models offer the best combination of simplicity, performance and transferability. The use of exhaustive searches for model calibration is likely to be impractical for other than a very small number of parameters.

The advantages of water balance models over more complex conceptual or process-based models are significant, and are the clear choice for this application. However, there are a number of aspects for consideration.

Model complexity is important as a larger number of parameters requires additional information in advance and creates difficulties for calibration. There is also the possibility of over-parameterisation, where redundant parameters reduce the physical significance of the model, such that it becomes 'little better than a statistical black box' [171]. However, three to five parameters should be sufficient to reproduce most of the information in the hydrological record [162].

The spatial and temporal scale also has a bearing on model complexity, with relatively simple models performing equally well on larger temporal and spatial resolution. This is due to parameters losing some of their significance, and suggests that the choice of model should reflect the size of basin in which it is to be used.

The process of calibration invariably means that the model becomes less physically based and more stochastic in nature [156]. However, the minimisation of the number of parameters determined by calibration will reduce this risk.

Irrespective of the complexity of the model, there will be some distortion of reality, particularly if, as is true for climate change assessments, data is sparse.

5.2.3 Hydropower Simulation

Chapter 4 noted several limitations in the representation of reservoir operations and hydropower production in climate impact assessments. Many of these can be addressed by the use of a reservoir operations model that allows hydropower production to be simulated in a physically sound manner. The simulation aims to operate the reservoir/hydro station in a similar manner to a station operator.

The basic aim is to account for water flows into and out of the reservoir, and this is generally achieved by the solution of the continuity equation that controls the level of reservoir storage

$$\text{Inflow} - \text{Outflow} = \text{Change in Storage} \tag{5.2}$$

The outflow consists of all flows of water out of the reservoir, controlled or otherwise, and includes: releases through the turbines resulting in generation; spillage; seepage or leakage into the surrounding soil or through the dam, and evaporation. The change in storage is the difference (if any) between the storage volume at the start and end of the period in question.

Solution of the continuity equation is non-trivial, as many components are interdependent. Storage and surface area are both functions of the water level (or elevation), and as they are determined by the topography of the land, the functions are rarely linear. The relationships can be determined by examination of contour maps or from digital terrain models, and dependent on the complexity, are used in either piecewise-linear form or as a continuous function. Storage is complicated by the existence of dynamic storage, where water flowing from the reservoir entry towards the impoundment creates a shallow wedge of water. Whilst important for short time scales, dynamic storage is often ignored.

The losses are also related to the reservoir level: seepage is influenced by the water pressure; evaporation is a function of reservoir area; and energy production is a function of available head.

Operating Rules

In operating reservoirs a trade off must take place between using the water for production in the current period and possibly being short in later periods, or postponing its use with the possibility of too much water and subsequent spillage. Operational policies must be tailored to allow optimal use of this limited resource. This is generally achieved through the use of rule curves.

Rule curves define the desired storage volumes and discharges at any time of the year as a function of existing storage volumes, demand for water or hydropower and possibly expected inflows [172]. Policies include one or more of four components:

1. Target storage levels.
2. Multiple zoning where rules define storage allocation.
3. Flow ranges providing a relationship between storage and releases.
4. Conditional rule curves.

Multiple zoning is common where there are multiple demands for water use or the need for flood control. As Figure 5.3 indicates, the reservoir is split into storage zones. The storage level will be within a particular zone and that will determine how the reservoir is operated and the magnitude of releases. The uppermost zone is the flood control zone which is empty except when regulating floods, and below that the conservation storage zone, which stores water to meet demand for power, irrigation or other. The dead storage zone represents the lowest level for power generation and provides space for sedimentation. The conservation zone is often split into two or more parts where differing levels of demand fulfilment can occur, with the lower buffer zone reserved for minimum operational purposes. The flood control allocation can be fixed throughout the year if floods can be expected at any time. Where floods follow more seasonal patterns, storage is allocated according to flood magnitude and probability, and such 'joint-use' schemes tend to provide more efficient use of available space. The buffer zone storage can also vary throughout the year.

The other common method of operating reservoirs is to develop relationships between releases and storage. Often linear, releases can be a function of storage alone, or inflow and other factors. Relationships relying on storage alone (*e.g.* ReVelle [174]) are likely to be relatively inefficient, so conditional rules which define releases on the basis of expected inflows improve matters. Figure 5.4 shows an operating rule that determines releases on the basis of available water, with the release satisfying the target energy fixed over a wide range of availabilities. The ramp on the right aims to prevent spillage as the reservoir nears capacity, while the decline to the left would reflect lower releases as availability falls.

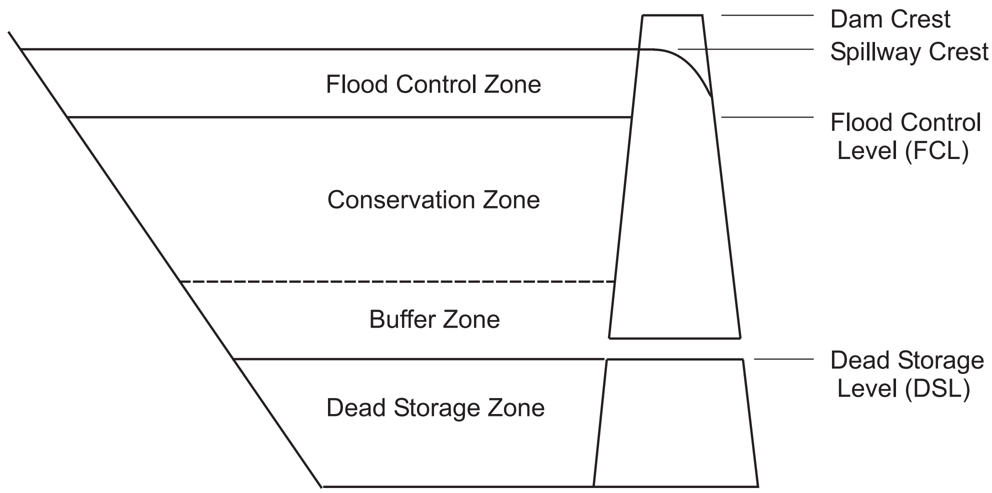


Figure 5.3: USACE defined reservoir storage zones and levels [173]

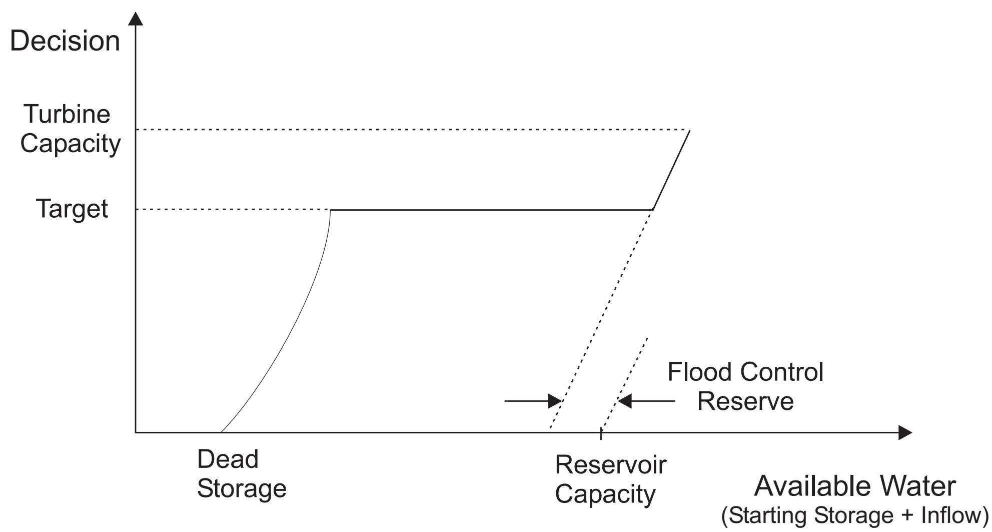


Figure 5.4: Standard reservoir operating rule [175]

Operational Strategy

The reservoir rules are determined on the basis of the desired operational objective, of which a number are possible [176, 177]:

- Maximise firm energy - production that can be met under the most adverse conditions.
- Maximise annual energy - under average water conditions.
- Maximise energy benefits - if energy values vary monthly, production will focus on higher value periods.
- Maximise dependable capacity - storage maintained at or above the rated head.
- Variable draft - storage is drafted for energy production based on the market value.

The first strategy is the classical approach to storage regulation, and applies mostly in hydropower dominated-systems where there is no alternative resource to make up the deficit. Originally determined by mass curve analysis, it is now more common to use sequential stream flow routing [129, 177]. While it is possible to meet the firm (or ‘primary’) energy target alone, this will waste valuable ‘secondary’ energy. To ensure good use of this additional energy, and flexibility towards non-power uses, rule curves are developed to determine reservoir operation.

The alternative strategies trade lower reliability for increased flexibility or increased benefit. Variable draft operation is increasingly common and relies on the creation of an economy guide similar to Figure 5.5. The economy guide relates long term thermal generation cost to the system energy in storage, and is normally computed by stochastic dynamic programming (SDP) methods. The optimal water use will allow the storage to fall to the level associated with the thermal cost in a given period. Using too much water results in a lower storage than optimal resulting in a high current ‘cost’, and vice versa. The logical basis for this is that any water spilled has no value, while close to the dead storage level the value is high. Originally developed for combined hydro-thermal systems, variable draft operation lends itself well to liberalised markets, where the optimisation can be applied to individual generating companies. Liberalised systems allow alternative water valuation approaches, including the use of historic earnings [178]. The uncertainties surrounding long-range thermal costs and demand means variable draft guides generally do not apply beyond a year ahead, and will be continually updated.

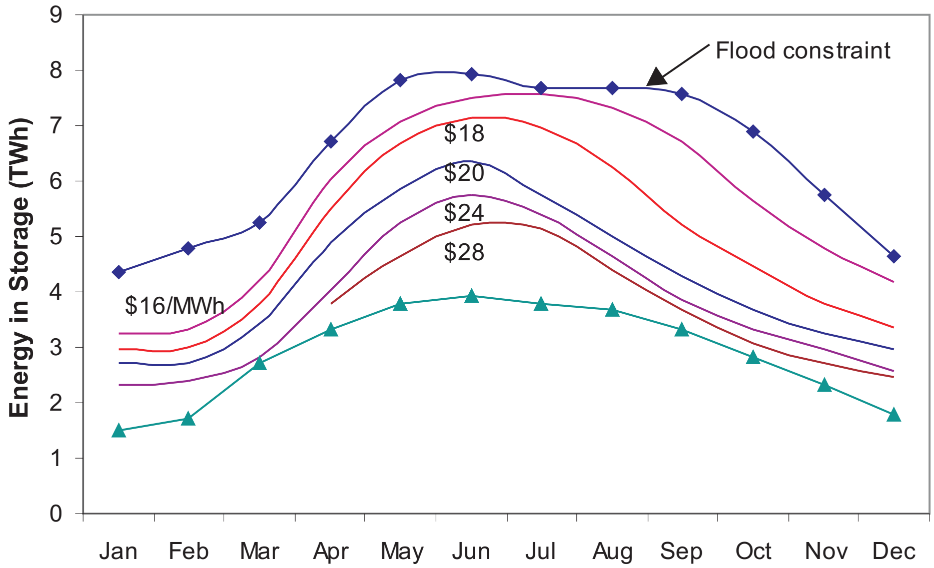


Figure 5.5: Marginal value of water in storage [179]

Foresight

The use of information is an important consideration for hydropower simulation, and if the model is to operate in a realistic manner, it should use the same level of information available to a real-life operator. This avoids problems with 'foresight' where the model has more information available than the operator, or 'short-sight', where the opposite is true [180]. Several approaches are possible. *Perfect information* assumes prior knowledge of inputs and demands, and will deliver the theoretically optimal operation. This is generally unobtainable and may result in under-designed systems. Good *forecasts* are generally available for system demands and river flows, and so modelling on this basis will produce reasonably realistic operation. In the absence of a forecast, *corrective action* can make use of information as it becomes available in order to optimise operations. The *commitment* to the meeting of a fixed requirement without regard for conditions or opportunities is likely to result in the greatest inefficiencies. Overall, the reliance on forecasts will avoid both fore- and short-sight and provide the most accurate simulation of reality.

Computer Packages

A wide variety of reservoir simulation tools are available. The US Army Corps of Engineers have developed some of the industry standard packages including the HEC-3 reservoir system analysis for conservation model [181], and the larger HEC-5 flood and conservation model [173]. Commercially available software includes the

Hydrocomp Forecast and Modelling package and a real-time operational simulation model from Hydrosoft Energie [182].

The complexities of operating multiple hydropower schemes has forced the development and use of designated models. Most authorities responsible for hydropower production will have their own, for example, the Tennessee Valley Authority model [183] and HYDROSIM used by the Bonneville Power Administration [177].

Operating Rule Optimisation

Much of the water resources literature is devoted to the design, application and assessment of optimisation techniques. In addition to classical or Lagrangian optimisation, reservoir rules have been developed by linear programming, dynamic programming (DP) and non-linear programming.

Linear programming methods are common in many problems relating to the electricity industry. The key assumption is that relationships between variables and the constraints imposed are linear, and these are generally solved using matrix methods. Both deterministic and stochastic approaches have been employed, as have so-called 'chance-constrained' methods which reflect the probability conditions on constraints [184]. The literature contains many examples of linear decision rules that guide release quantities as a function of storage and other variables (similar to Figure 5.4).

Dynamic programming was originally formulated to optimise multi-stage decision processes, and much of its popularity stems from its ability to deal with the non-linear and stochastic characteristics of real systems. Large problems can be reduced to sub-problems that can then be solved recursively. The solution follows from the 'principle of optimality' which allows the decision tree to be reduced to a series of single-step decisions. A number of DP techniques are available but the standard approach for water resources is the use of stochastic dynamic programming (SDP). SDP employs the serial correlation of inflows to develop a conditional probability matrix, and this requires that both state (storage) and decision (release) variables are discretised. Effective discretisation is important to balance accuracy and computational effort. Stochastic techniques tend to produce more conservative operating procedures but higher reliabilities than deterministic ones [175].

The application of non-linear programming to reservoir operation has previously been limited by computation and a lack of effective algorithms for large scale optimisation [184]. They have advantages over other techniques in that non-linear constraints and non-separable objective functions can be handled, but the inclusion of the stochastic nature of inflows is problematic. A wide variety of search algorithms have been applied to problems, including the use of genetic algorithms [185].

Most of the above techniques are optimised on the basis of the value of an objective function. The objective function normally consists of terms that measure the benefits of reservoir operations as well as penalties for breaking 'soft' constraints (*e.g.* encroachment into the flood-control zone). Reviews of optimisation approaches and the necessary objective functions are available in Yeh [184], Mays and Tung [186], and Wunderlich [180].

Recommendations

Reservoir operations modelling is well defined and documented, with the industry standard HEC-5 approach particularly so. Accordingly, HEC-5 will be used as the basis for modelling the reservoir and hydropower station. The correct choice of operating rules is highly dependent on the operating strategy, the reservoir purpose and in particular the market type. These factors are considered in the next section.

5.2.4 Electricity Market Model

The continuing trend towards electricity market deregulation and liberalisation has led to a great deal of commercial and academic research activity on the effective modelling of electricity markets. This has primarily been due to the need of market participants to gain competitive advantage or understand their risks, and for regulators in understanding and determining strategies for increased competition.

Market modelling is used for production planning, contract negotiation and investment appraisal. In this application the requirement is to create a revenue stream from production estimates by determining the selling price in each period. The nature of the revenue stream depends on the type of market, the type and availability of contracts and the type of generating plant.

Market Simulation and Contracts

Energy prices in traditional systems are generally set by purchase tariffs determined by the Utility. In well regulated systems, prices rises are often restricted to the level of inflation or less, and as such are relatively easy to project forward in the short and medium term. The real difficulty is the prediction of inflation rates, which often leads to the use of the long term average.

For liberalised markets, prices vary according to the demand level and generator availability, and accordingly are more difficult to predict. The system marginal price for any period can be determined from the least cost schedule determined by a variety of different methods. In the UK the unconstrained least-cost schedule is currently created by the Generator Operation and Loading program, which ranks Generator's bids in ascending order [73]. In the long run the bids are expected to reflect the marginal cost functions for each plant (Chapter 3), as would occur with perfect competition. As such, it is possible to create estimates of market price based on these marginal cost functions [87].

In reality the bids do not perfectly reflect marginal costs, and can vary considerably from period to period. The ability for a Generator's bid to depart from the marginal cost could reflect the fact that a perfectly competitive market is not in place, and that 'gaming' is occurring. This could be through setting prices artificially high or by restricting capacity to force up the capacity payment component [88, 89]. There has been some consideration of non-perfect or oligopolistic competition in the literature [187, 188, 189].

An alternative approach to scheduling approaches is to develop statistical models of actual price movements. The standard method in financial markets is to use a log-normal model, but this does not work well with electricity markets, partly due to differing short and medium term behaviour. Mean-reversion models have been proposed as an alternative [83].

Whichever method is used to predict market prices, they can often only be relied on in the short term. With the timescales involved in investment appraisal there are considerable uncertainties surrounding fuel prices, regulatory involvement and plant mix. These all have the capacity to fundamentally alter the price regime, and pose a significant risk to the investor and lenders. The use of contracts for reducing risk is common and has a major effect on market pricing and participation.

Hydropower Operation

The traditional use of hydro in mixed hydro-thermal systems is to minimise thermal production costs [190]. With liberalised systems the use of cost alone as a decision variable is inadequate, given the primary objective of profit maximisation. Given the very low variable cost of hydropower production, it could conceivably be scheduled to operate in any time period, and in fact is only limited by the resource. Assuming that the hydro company cannot influence prices (*i.e.* it is a 'price taker'), the limitation requires that hydro is used in the highest price periods, which normally are the peak demand periods. Therefore, the optimal operational strategies in both coordinated and competitive systems are the same [191].

Accordingly, a knowledge of demand should allow scheduling on the basis of available water, but the issue of price determination still exists. Average prices are possible, but this implies that production can occur across all sub-periods which may not be the case. The assumption of hedging contracts could be useful in that it allows a single price to be used. However, difficulties arise regarding how to treat energy in excess or deficit of contracted quantity. Irrespective of the market, or simplifying assumptions, the simulation of the revenue stream and the creation of optimal scheduling is non-trivial, as the weight and variety of available literature shows (*e.g.* Diaz and Fontane [192], Maceira and Pereira [193], among others).

Recommendations

Many of the locations suitable for new hydropower schemes lie within underdeveloped electricity systems which are unlikely to move towards deregulation in the foreseeable future. As such, and given the considerable difficulties with simulating prices in liberalised systems, as well as the widespread use of power purchase agreements, it was deemed unnecessary to consider market price modelling other than price regimes resulting from tariffs or power purchase agreements.

Generators derive some revenue from activities other than the supply of active energy. This is particularly true in liberalised systems, where ancillary services attract payments from the system operator, and opportunities exist for hydro plant to engage in spot contracting. As such payments are (mostly) independent of climate change, and represent a relatively small proportion of income they therefore will not be considered further.

5.2.5 Financial/Economic Model

Although financial and economic modelling is fairly standard and the use of UK accounting standards is assumed, a number of points require qualification:

- As depreciation reflects the contribution of the investment to the profit and loss account, the reducing balance approach is more appropriate.
- Separate depreciation rates for different plant types are common, but this analysis assumes a single depreciation rate, and no plant replacements.
- Loan interest rates and inflation can vary over the economic lifetime of a generating station, but for simplicity fixed rates will be assumed.
- Although it is common for feasibility studies to incorporate foreign exchange into the financial analysis, the nature of this study suggests that such consideration is too detailed.

5.3 Data Requirements and Availability

The structure and scope of the software model is strongly influenced by the availability and quality of input data. This section examines the type of data required, and the type and quality of available data. Guidelines for data needs and use are then outlined.

5.3.1 Requirements

For the adapted feasibility study approach a series of different types of data will be required. Although similar to those required by the standard approach, it includes climate and climate change data, among others:

- time-series of climate data,
- time-series of river flow data,
- technical and operational details of the hydropower scheme,
- current and future market conditions and prices, and
- economic projections and financial information.

5.3.2 Availability

Observed Climate and Climate Change Scenarios

Standard feasibility studies tend to limit the use of climate data to identifying wet and dry years for use in testing the robustness of operational methods. At the lowest level, weather stations can provide a range of data from individual locations, and this can be gained from the meteorological office of the country in question, or from the archives of the WMO (either of which may attract a fee). The type of data will vary by station as will the measurement interval (*i.e.* daily, monthly *etc.*) and the quality of the data.

The climate change issue has led to the development of a variety of global and regional datasets of observed climate variables. Leemans and Cramer constructed one of the first and provide monthly mean values for a range of climate variables on a $0.5°$ latitude by $0.5°$ longitude terrestrial grid [194]. A more recent version was created at the Climatic Research Unit, University of East Anglia (CRU) and consists of two datasets: a mean monthly climatology for 1961-1990 and a time-series climate from 1901-1996 [195, 196].

The output of GCMs can be gained directly from the modelling groups, or more easily through the Data Distribution Centres (DDC) set up by the IPCC to facilitate research on climatic change. The DDCs possess the results of runs corresponding to the Business-as-Usual or IS92a scenarios of the IPCC Assessments including monthly anomaly fields, control and equilibrium values. Some transient experiments are also available, as is the CRU observed mean monthly climatology.

River Flow

River flow data can be sourced from the resident statutory body, for example, in the US this would be the United States Geological Survey. Otherwise, the WMO holds a range of data for several thousand gauging stations worldwide, and can be accessed via the Global Runoff Data Centre (GRDC) at the German Federal Institute of Hydrology. Where river flow data is not available, other techniques are required to estimate flows at the site in question. These include the use of other catchments as analogues and hydrological modelling.

Reservoir, Market and Finance

The availability of data depends on the stage of development of the scheme. Although information on capacity and cost is generally widely reported in industry journals (*e.g.* International Journal on Hydropower and Dams), more detailed data (*e.g.* reservoir storage-elevation curves), is more difficult to access. Generally, more data becomes available as the scheme advances, with information on operational schemes found in many locations.

Where a scheme is planned or under construction, the feasibility study report will often provide the essential assumptions and calculations surrounding the design, projected operation and financial appraisal. The studies can often only be accessed through the project sponsors or consultants, and there may be reluctance if the details are regarded as confidential.

If the development is at pre-feasibility stage, then the project parameters have to be estimated through a simplified study of available resource, potential market and financing. For example, the capital costs can be estimated parametrically, or through the adoption of typical values (*e.g.* installed unit cost of $1000/kW).

5.3.3 Accuracy and Use

All recorded data is subject to errors. Spatial climate data is influenced by the density of weather stations, both in terms of the true climate but also in terms of the ability to cross-reference values to ensure quality. In Western countries, weather data is monitored by fairly dense networks of stations and can generally be assured. In developing countries this is not the case, as since the decline of colonial power the number of stations has fallen. Unfortunately, these regions tend to have the greatest need for climate monitoring and assessment. Gauged river flows are also subject to error, due to the irregular sampling of flow. In general, measurement error reduces with longer time steps, with for example, monthly river flow errors limited to around 2% [197].

Economic projections are notoriously difficult, particularly over the time scales required for investment appraisal, as are those relating to cost and construction time. Estimates of electricity market size, growth rate and structure are also problematic, particularly in a time of rapid change. The use of feasibility study assumptions is a reasonable approach to negating the problems of projecting future conditions, particularly as these are used in determining development suitability. Therefore, for the purposes of this study, such projections will suffice.

To limit the influence of measurement and estimation errors, it is sensible to limit the number of items of data required for analysis. A second advantage would be to increase the transferability of the software as fewer examples would be precluded through data insufficiency. However, a trade-off must be carried out in order to maintain realism and accuracy.

As the analysis involves many years of data, feasibility studies tend to use monthly timesteps. It is reasonable to follow this approach, particularly as observed climate and GCM output is most easily accessible as monthly data. The use of monthly time steps will, however, have a detrimental effect on accuracy, a fact noted in some existing feasibility studies. For example, there is a tendency for over- and under-estimation of hydroelectric production and spillage, respectively, although this is relatively minor compared to other estimates. While it is possible to apply correction factors to monthly data to improve the accuracy and realism (*e.g.* Three Gorges [130]), it is uncertain whether these would remain valid with altered flow regimes.

5.4 Analytical Approaches

Even with a model that can translate climate into financial performance, the question still remains concerning how to use it, and whether it is suitable for such tasks. Three possible analysis methods present themselves.

5.4.1 Sensitivity

Most hydrological and water resources impact studies test the sensitivity of the system to predefined changes in climate. A similar procedure is already used in capital analysis to ascertain the sensitivity of project returns to changes in construction cost, build period or financing rate [198]. The use of uniform changes in climate parameters would be a useful extension, and allows the relative effects of changes in all project parameters to be compared.

5.4.2 Scenario Analysis

Scenario analysis provides results on varying collections of parameters, to provide an indication of performance under different climes. As mentioned in Chapter 2, the application of GCM derived equilibrium or transient climate anomalies provides the basis for the analysis, and allows the effect of differing policy choices to be examined.

5.4.3 Risk Analysis

The outcomes from scenario analysis tend to be heavily reliant on the choice of internal and external parameters. As such, the use of single scenario values for (say) historic river flow data may well lead to a poor decision if the reality is significantly different from the estimate. The careful use of risk analysis techniques can help overcome this.

Risk analysis often uses Monte Carlo techniques to generate distributions of possible outcomes with different study parameters [198]. Each notable variable is assigned a statistical distribution (generally Gaussian), and the value is chosen at random for each run. To provide a statistically significant sample, the process is repeated many times (generally more than 1,000). The resulting histograms then provide the basis for the risk assessment. Monte Carlo analysis tends to be computationally intensive and there are difficulties in selecting suitable distributions for relevant parameters. The particular difficulty for this application would be the tendency of other changes to disguise the effect of changes in climate, and a lack of control over the actual climate changes being modelled.

One possible solution to this would be the use of Markovian models. They have been used for many years to provide synthetic series of river flows. Statistically indistinguishable from the original flow record, such flows have been used to extend the record period, fill gaps and provide alternative flow scenarios to test the robustness of water resources systems [144].

Markov (or auto-regressive) models assume that record data is self-correlated, and future values can be determined from current values and the correlation together with a random element. Monthly flows are often correlated with the preceding months flow, and as such, high or low flows tend to continue. Such 'persistence' is dependent on the capacity of the catchment to hold water or possess 'memory'. An expression for generating future monthly flows (q) can be gained from analysis of the statistical properties of the data (monthly mean μ, standard deviation σ and correlation coefficient between months ρ) and a normal random number (t):

$$q_{i,j} = \mu_j + \frac{\rho_j \sigma_j}{\sigma_{j-1}}(q_{i-1,j-1} - \mu_{j-1}) + t_i \sigma_j (1 - \rho_j^2)^{\frac{1}{2}} \tag{5.3}$$

where i and j represent the sequential and periodic indices.

Similarly, for this application it is possible to create synthetic series of climate data, although the monthly persistence of precipitation or temperature tends to be lower. For example, a risk analysis of hydroelectric production reliability in central Greece relied on the use of a first order Markov model to provide alternative sequences of current climate data [134]. The climate change anomalies were then applied to each one in turn to build up the distribution of outcomes. As with single scenarios of climate change, Markov approaches cannot take account of changes in the temporal structure of climate sequences. However, it conceivable that changes in the temporal structure could be considered by altering the statistical properties of the climatic variables, either from the output of GCMs or on an arbitrary basis.

Overall, all three approaches can play a part in understanding the changes that will occur from global warming.

5.5 Summary

This chapter presents the requirements and specifications of a software tool for use in determining climatic impacts on hydropower and investment in it. Available modelling methodologies and approaches are critically examined for their suitability, and recommendations made. The requirements and availability of data is considered and leads to the conclusion that operating the model on a monthly time step over the desired number of years is most suitable for this purpose. Several analytical approaches are presented and deemed suitable for the purpose.

Chapter 6

HydroCC Simulation Tool

This chapter describes the theoretical and mathematical basis of the climate impact software tool together with details of its implementation and features.

6.1 Software Implementation

The implementation of software suitable for executing rapid assessments of hydropower scheme sensitivity and risk to changing climate is the primary means of examining the project hypothesis set out in Chapter 1. The name chosen, 'HydroCC', an acronym for Hydropower and Climate Change, is intended to reflect its nature. HydroCC is a sizeable and complex software application, relying on over of 20,000 lines of code (written by the author) for its simulation and functional capabilities. HydroCC enables a financial appraisal of a suitable scheme to be performed under current or a range of possible future climatic conditions, and follows the process illustrated in Figure 5.1.

To allow ease of use on a Microsoft Windows PC a suitable graphical user interface (GUI) was necessary, and this limited the range of programming environments available. The language chosen for implementation was Microsoft Visual C++, which is designed for object oriented programming (OOP) techniques which were adopted for the software model.

OOP provides a data abstraction model that allows objects to be defined according to application requirements. The key concept is that of 'class', which allows data hiding, data initialisation, type conversion and operator overloading. More advanced features include the concepts of 'inheritance' where an object can incorporate features from its parent, and 'polymorphism' which allows different objects to respond to the same function call in different ways. Each component of the HydroCC software is implemented as an object, which, although requiring additional programming effort initially, benefits from the modular approach in terms of fault finding, flexibility and efficient maintenance. Sub-objects provide much of the functionality.

The C++ language was developed by Stroustrup, and is a superset of the C language, which allows a high degree of code re-usage and interchange. Many texts deal with the use and structure of the language [199, 200] but the definitive texts are by Stroustrup [201, 202]. Other parts of the literature deal with the construction and design of the GUI, and the intricacies of the Windows environment (*e.g.* [203]).

While graphical user interfaces are convenient and efficient means of editing disparate pieces of data, it is more convenient to allow larger bodies of connected data (*e.g.* time series data) to be entered and output in text files. This allows the use of proprietary spreadsheet packages to edit and manipulate data and create graphical representations.

The software is structured as a Single Document Interface application, which provides functionality for saving and retrieving data through 'serialisation' in digital form. Carefully written code allows the attributes of all model components, together with time-series data to be managed as sub-components of a 'document' object (similar to a Microsoft Word document), although there was only limited scope for the use of the document-view architecture.

Figure 6.1 shows the basic HydroCC application and some of the major GUI interfaces to the components, some of which are described in more detail in the following sections. These interfaces allow the financial appraisal of a given hydropower scheme to be carried out, and many of the interfaces relate to components of the appraisal process illustrated in Figure 5.1.

6.2 Climate and Climate Change

The climate component supplies available climatic data to the hydrological model following the application of relevant change scenarios. Three combinations of climatic data can be used in HydroCC, reflecting the potential evapotranspiration methods catered for. These are the Priestley-Taylor and Hargreaves methods and the use of PET data (considered later). From the 'Climate Edit' dialog (Figure 6.2), the differing data requirements can be displayed, and data loaded or removed using the relevant controls.

6.2.1 Climate Change Scenarios

Climate change scenarios can be loaded into the system, using the relevant controls, which create a sheet where key details can be entered and the actual precipitation

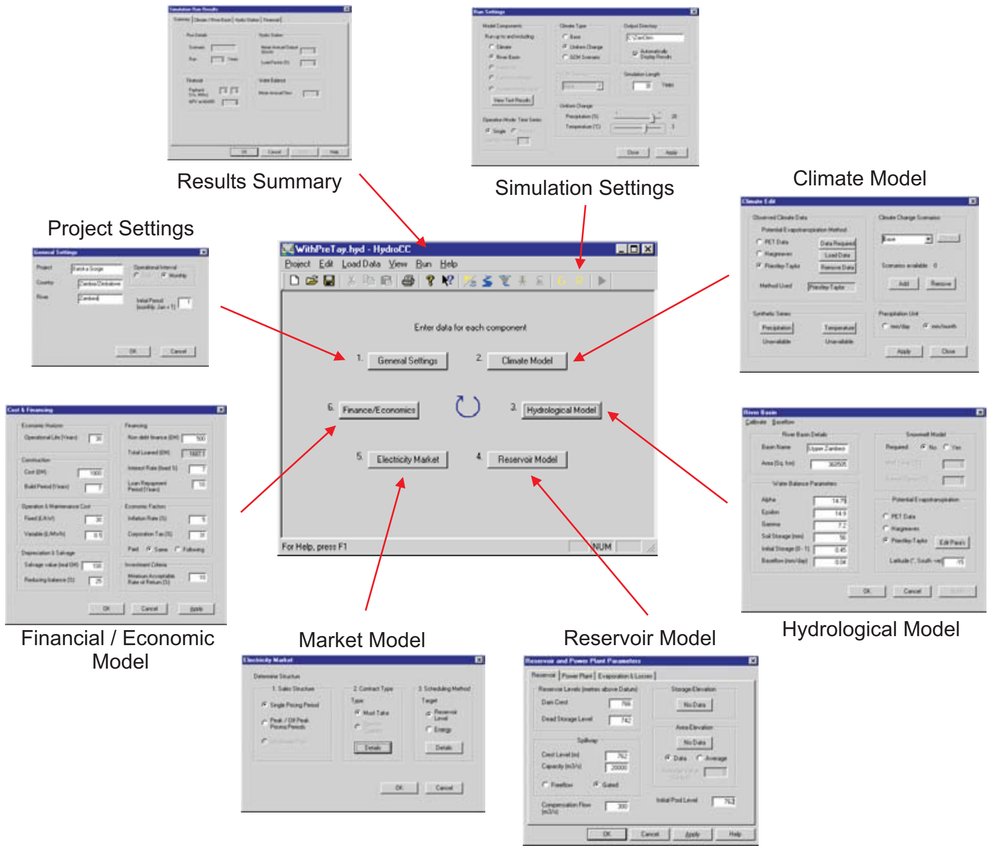


Figure 6.1: HydroCC application and major dialog sheets

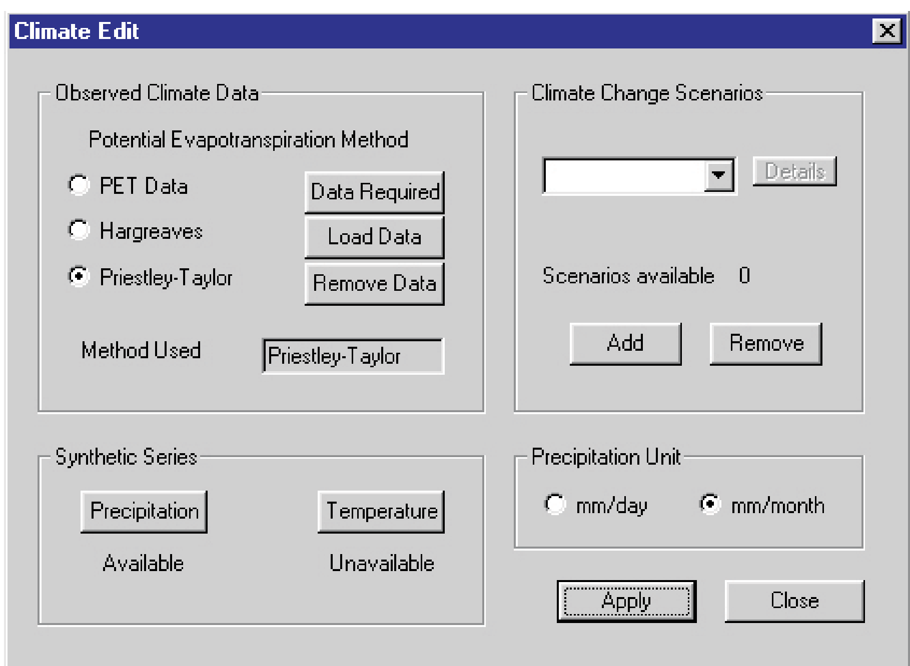


Figure 6.2: Climate and change scenario settings

and temperature change time series loaded. Once loaded, the scenarios can be edited using the list and accompanying button, and the data remains with the document until such times as it is removed. A corresponding entry in the simulation settings sheet (Section 6.8.1) allows the relevant scenario to be selected for use. As the major effects of climatic change will be as a result of changes in precipitation and temperature and following convention, only these are altered on a proportional and absolute basis, respectively.

6.2.2 Synthetic Series

To enable limited risk analysis capability, the climate component manages the analysis, creation and storage of synthetic precipitation and temperature series. Controls on the Climate Edit sheet enable the display of a dialog sheet (Figure 6.3) containing the necessary statistical measures for an indication of the relationships. The sheet allows the data to be analysed rapidly, and the results displayed. After necessary adjustments (*e.g.* ensuring non-zero standard deviation, to prevent divide-by-zero error), the length and number of synthetic series can be selected and then generated according to Equation 5.3. The synthetic series can be viewed as a text file written to a user defined directory. Once both sets are available, the multiple dataset routines become active.

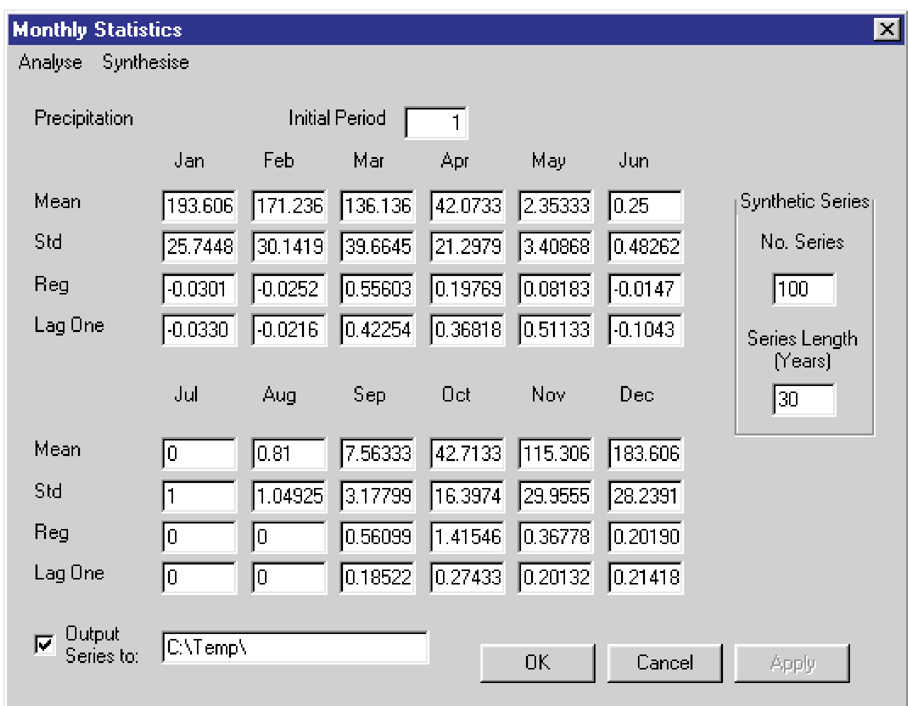


Figure 6.3: Synthetic series analysis and generation dialog

6.3 'WatBal' Hydrological Model

The hydrological model component converts the climate data into estimates of river flow, and the simple water balance model incorporated is known as 'WatBal'. The framework for the model was originally developed by Kaczmarek and Krasuski [204], and elements of their approach were adapted by Yates [205]. This simple lumped-parameter model represents the catchment as a single storage 'bucket' with precipitation input and outputs of evapotranspiration and several runoff components (Figure 6.4).

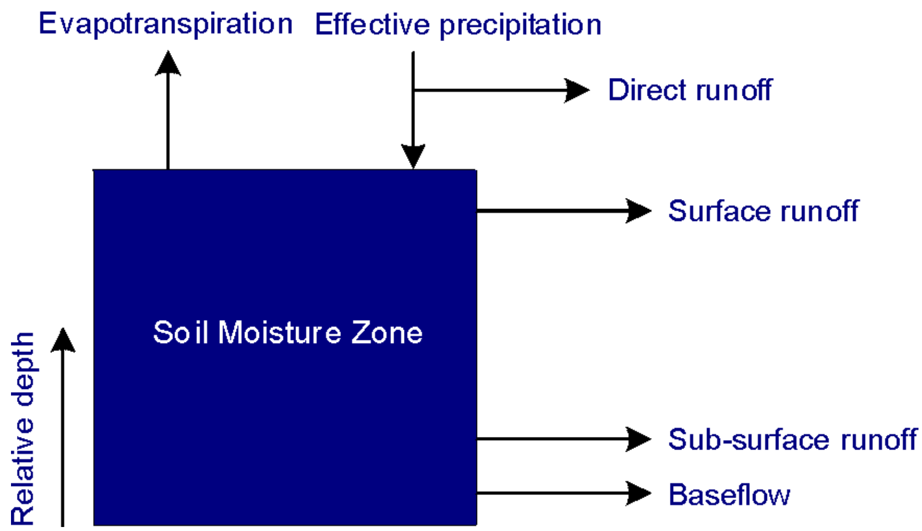


Figure 6.4: Conceptual structure of WatBal model [205]

Yates' model includes a direct runoff term which allows a fraction of rainfall to immediately become runoff without entering the soil zone. However, determination of this fraction requires familiarity with the catchment being modelled, and as this could not be guaranteed the term was omitted, following the example of Bowling and Strzepek, in using the model for land use change experiments [168].

The WatBal model has a number of distinct advantages over other simple water balance models examined (*e.g.* Gleick [167], Xiong and Guo [206]). It has been widely reported and used in a variety of catchments, differing in climate type and size [139, 207], and for examining continental scale runoff [208]. It has also been used to assess the effect of spatial and temporal data resolution on climate change assessments [209], and has compared favourably with other water balance and regression models. For most of these applications it has managed to produce relatively high correlation coefficients for both calibration and validation periods.

6.3.1 Water Balance Representation

The model is novel in that it uses continuous functions of relative storage to represent runoff and evapotranspiration. A second difference is the representation of the mass balance as a differential equation, allowing a range of different time scales to be used. It is given by [205]:

$$S_{max}\frac{dz}{dt} = P_{eff}(t) - R_s(z,t) - R_{ss}(z,t) - R_b - AET(PET,z,t) \qquad (6.1)$$

where S_{max} is maximum soil moisture storage, z is relative storage, P_{eff} is effective precipitation, R_s is surface runoff, R_{ss} is sub-surface runoff, R_b is baseflow and AET is actual evapotranspiration. All values are in mm/day except S_{max} (in mm) and z (which varies between 0 and 1).

The inputs to the model are effective precipitation and potential evapotranspiration. In most cases the former is simply the incident rainfall, although for snow dominated catchments, a snowmelt and accumulation model is required (Section 6.3.2). PET can be estimated using a wide range of methods which are examined and compared in Section 6.3.3.

The key variable in the model is the relative soil moisture level, defined as the fraction of the maximum S_{max}. The maximum soil moisture depends on the type of soil and topology, with deep soils, characteristic of tropical forests, possessing a large capacity, and thin rocky soils in mountainous areas having a relatively small capacity. The individual components of Equation 6.1 are presented in more detail as follows.

Actual evapotranspiration (AET) is a function of the soil moisture state and PET, and while linear relationships have been used, non-linear ones are more realistic [205]:

$$AET(PET,z,t) = PET(t)(\frac{5z - 2z^2}{3}) \qquad (6.2)$$

With the removal of the direct runoff component, all effective precipitation is assumed to enter the soil. Some will leave as surface runoff, depending on the precipitation level relative to the baseflow and the soil state and the surface runoff exponent (ε). Where there is a deficit, all precipitation percolates deeper into the soil, according to:

$$R_s = \begin{cases} z^{\varepsilon}(P_{eff} - R_b) & \text{for } P_{eff} > R_b \\ 0 & \text{for } P_{eff} \leq R_b \end{cases} \qquad (6.3)$$

The sub-surface discharge R_{ss} is dependent on the storage state and the sub-surface runoff coefficient, α (mm/day) as Equation 6.4 shows. Yates states that, for most catchments, the relationship is quadratic (*i.e.* sub-surface runoff exponent $\kappa = 2$), although for some a lower, more linear relationship is more appropriate indicating lower moisture retention capacity, *e.g.* gravel dominated catchments [205].

$$R_{ss} = \alpha z^{\kappa} \tag{6.4}$$

Total runoff R_t (in mm/day) for a given time step is given by the sum of the three components with baseflow determined from the 95% exceedance flow:

$$R_t = R_s + R_{ss} + R_b \tag{6.5}$$

The complexity of the differential equation precludes analytical solution, necessitating a numerical method. Various solution methods are available, ranging from the simple Euler's method to more complex predictor-corrector methods. The most common approach uses a Taylor expansion of the equation, although difficulties with computing higher derivatives, means that the approximate Runge-Kutta method is favoured. The Runge-Kutta method is accurate, stable and easily programmable, and requires only the first derivative to be found [210]. Although previous versions of WatBal relied on predictor-corrector methods, the Runge-Kutta was found to be acceptable.

6.3.2 Snowmelt Model

For catchments significantly influenced by snow, a snowmelt model is used to compute adjusted effective precipitation (P_{eff}). The behaviour of a snowpack is determined by energy balances but can be approximated using a number of techniques [211]. The use of degree-day data to determine the freezing and melting rates is common, but a relatively simple temperature method is favoured here as it avoids the need for degree-day calculations. It operates by comparing mean monthly temperature (T_i) with specified threshold temperatures for melting (T_l) and freezing (T_s), it accounts for snow accumulation (A) in the snowpack and the amount of snow that melts. The necessary equations are:

$$P_{eff,i} = mf_i(A_{i-1} + P_i) \tag{6.6}$$

where P_i is the incident precipitation in month i. The melt factor (mf) is given by

$$mf_i = \begin{cases} 0 & \text{for } T_i \leq T_s \\ 1 & \text{for } T_i \geq T_l \\ \frac{T_i - T_s}{T_l - T_s} & \text{for } T_s \leq T_i \leq T_l \end{cases} \tag{6.7}$$

where snow accumulation (in mm) is calculated from

$$A_i = (1 - mf_i)(A_{i-1} + P_i) \tag{6.8}$$

The correct estimation of the two temperature thresholds is important in the correct reproduction of observed river flows, as analysis with the East River and South Platte Rivers, both in Colorado, demonstrated [205, 168]. Specifically, it was found that temperatures control the timing and size of the melt, and the temperature range governs the melt rate.

6.3.3 Evapotranspiration Model

Potential evapotranspiration is a key input to the hydrological model, and can be estimated by a wide range of methods. A good summary and a guide to selecting the appropriate method is given by Shuttleworth [212]. Strictly there are two types of evapotranspiration calculation: potential evaporation ($\mathrm{E_p}$) and reference crop evaporation ($\mathrm{E_{rc}}$), which refer, respectively, to moisture loss from open water and an area of short grass. The latter tends to indicate lower rates of loss.

Other than pan estimators, most other methods are indirect and require significant calculation. The most complex evaporation model currently available is the Penman-Monteith reference crop measure which represents moisture flows as a network of resistances. The simpler Penman PE measure is given by:

$$E_p = \beta \frac{\Delta}{\Delta + \gamma}(R_n - A_h) + \frac{\gamma}{\Delta + \gamma} \frac{6.43(1 + 0.536U)D}{\lambda} \tag{6.9}$$

where Δ is the gradient of the saturated water vapour pressure curve, γ the psychrometric constant (kPa $^\circ\mathrm{C}^{-1}$), U is wind speed at 2m above ground, D is the vapour pressure deficit (kPa) and λ the latent heat of vaporisation for water (MJ/kg). R_n and A_h are, respectively, the net radiation exchange for and the energy advected to the water surface (both mm/day). β depends on the climate type and is taken to be 1.26 in humid and 1.74 in arid climates (relative humidity less than 60%) [212].

The complex models have significant data requirements which can be difficult to satisfy. The Priestley-Taylor reference crop measure is a radiation-based approach incorporating many of the features of the Penman model and provides similar estimates using far less information:

$$E_{rc} = \beta \frac{\Delta}{\Delta + \gamma}(R_n - G) \tag{6.10}$$

where E_{rc} is in mm/day, . For regional estimates the soil heat flux (G) is effectively zero [205].

Other radiation based methods include the Turc equation which performs well in humid climates [212]. PET is also correlated to temperature through the radiation balance, and as such many methods are based on temperature. All are empirical and therefore limited in their transferability. The better known examples include the Thornthwaite and Blaney-Criddle methods, but only the Hargreaves method is recommended due to its explicit link to the radiation approach [212]:

$$E_{rc} = 0.0023 S_o \delta_T^{0.5}(T + 17.8) \tag{6.11}$$

where S_o is the water equivalent of extraterrestrial radiation in mm/day, δ_T is the mean diurnal temperature range, and T is mean temperature (both °C).

The methods detailed here are very different in their approaches and strengths. The modified Penman is the most soundly based as it is most closely related to the Penman-Monteith measure which is the accepted standard measure. However, the smaller data requirement favours the more simple Priestley-Taylor approach. Yates and Strzepek found large seasonal differences in estimated PET values between several methods (see Figure 6.5), which led to a corresponding variation in runoff when applied to the WatBal model [140]. The study found that the Priestley-Taylor method was a good approximation to the modified Penman, and while results from the Hargreaves and Thornthwaite temperature-based methods differed from the physical methods, the degree was related to the complexity of the climate being modelled. Overall, the Hargreaves method produced a reasonable approximation to the more complex models.

Data availability is a key consideration in selecting a method for use. As Section 5.3.2 suggested, tabled observed data can be used to supply the needs of the models. Climate change scenarios are often limited to precipitation and temperature, and so other climatological variables are often assumed to remain constant or are scaled from other data. In addition to the primary climate data, the Priestley-Taylor method requires relative humidity and maximum daily sunshine hours, whilst the Hargreaves method requires diurnal temperature range. These are available in both the Leemans and Cramer [194] and the CRU databases [195, 196], and were adopted for the evaporation component.

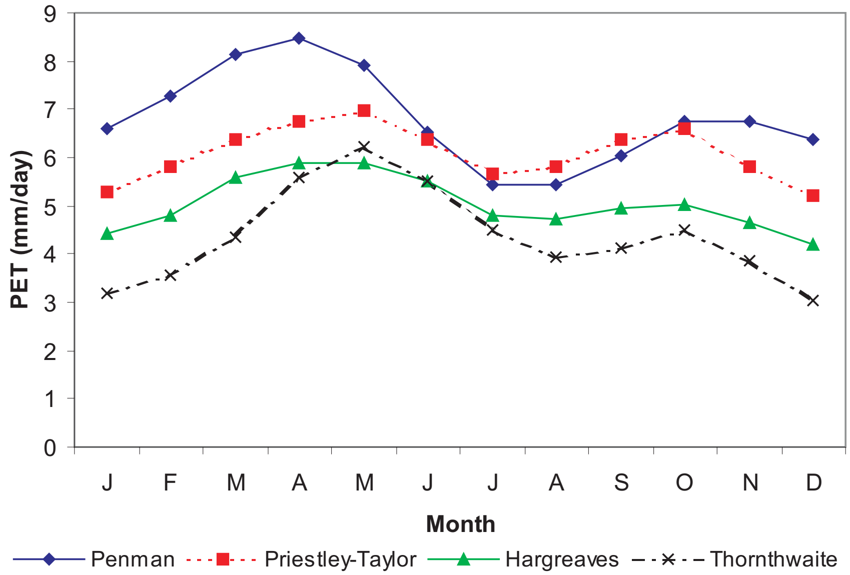


Figure 6.5: Potential evapotranspiration method comparison for Blue Nile [140]

6.3.4 Calibration

Several search methods have been employed to calibrate the various forms of the WatBal model. Yates used a heuristic approach while Bowling and Strzepek relied on a proprietary Genetic Algorithm produced by Palisade Corporation. They required this as they developed WatBal into a distributed form with a number of sub-catchments, necessitating the optimisation of two parameters per catchment. Yates optimised three parameters, α, ε and S_{max} on the basis of minimising RMS error, while Bowling and Strzepek's version only relied on two, as the latter was based on the land use. Neither model optimised κ, initial soil moisture storage or the snowmelt threshold temperatures.

To provide flexibility and allow the same basic solution method for the reservoir model, the choice of a Genetic Algorithm is sensible for optimisation of the water balance model. The increased flexibility allows the investigation of the effects of including other parameters in the optimisation. The operation of the GA is considered in Section 6.7.1. The Nash-Sutcliffe criterion (Equation 5.1) provides the basis for the objective function, and an exhaustive search routine allows GA performance to be determined.

6.3.5 Control and Operation

All aspects of the WatBal component are configured from the same dialog (Figure 6.6) which allows editing of the major parameters. The desired PET method is selected, and for the Priestley-Taylor approach a further dialogue prompts for specific parameter values. If the PET setting is suitable the snowmelt model can be activated, and necessary temperature thresholds entered. The baseflow runoff component can be estimated by determining the 95% exceedance flow and activated from the menu command item. The calibration procedures are also accessed from the menu, and the chosen values can automatically update the sheet.

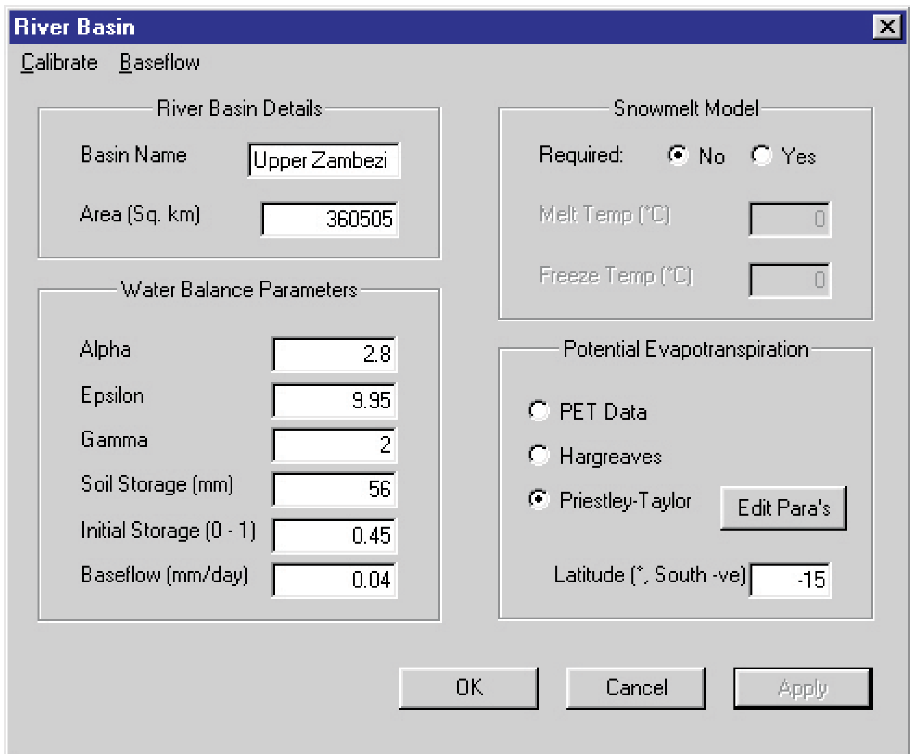


Figure 6.6: WatBal dialog

6.4 Reservoir Model

Most of the technical and operational parameters associated with the reservoir and hydro station component are edited through a series of property sheets (Figure 6.7). In addition, they allow the reservoir storage- and area-elevation data to be loaded.

The considerable influence of the electricity market has influenced the structure of the model, with both generation targets and maintenance scheduling determined from the market module dialog. The maintenance schedule enables units to be

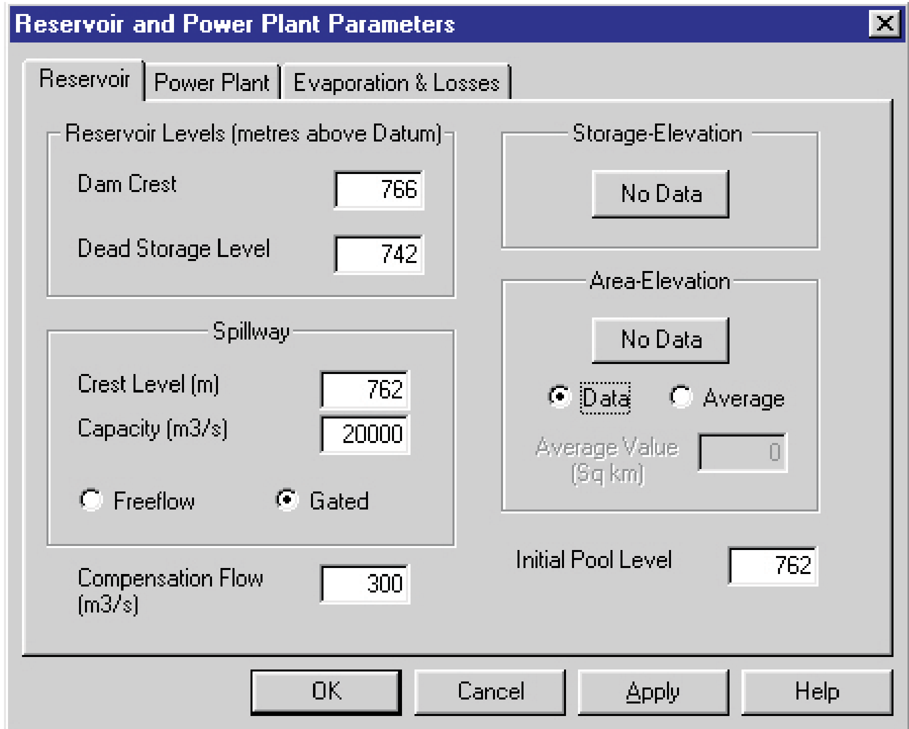


Figure 6.7: Hydro scheme technical parameters

withdrawn from operation in any month which has the effect of restricting turbine capacity and flow limits.

The reservoir model is designed to follow either of two rule curve types mentioned in Chapter 5. These are multiple zoning and target storage levels, and both routines operate iteratively to capture the inter-relationships between many aspects of operation including hydraulic head and evaporation levels. A series of operating codes output along with production data allow decision-making to be followed from period to period, and indicate, for example, when energy limits have been reached. In order to capture the inter-relationships between water levels and releases or evaporation the storage or continuity equation is solved iteratively.

6.4.1 Multiple Zoning Operation

The routine is based on that used by HEC-5 and was inferred from the detailed user manuals [173]. As Figure 6.8 indicates, the routines assess the feasibility of meeting the energy target while taking account of the end storage levels, and flow and energy limits. If, for example, the releases necessary to meet an energy target would leave the final storage in the flood control zone, then additional releases occur to leave the level below the flood control level, assuming that the additional energy produced can be absorbed by the system. If the flow or energy limits would be exceeded then the release takes place at that rate, which may not be sufficient to prevent spillage. An end storage above the FCL will result in additional production in the following period to ensure that the zone is evacuated rapidly. At the other extreme, a final storage in the buffer zone will lead to a reduction in production, ensuring that compensation requirements are met.

The model is configured to deal with sub-periods or 'time-slices', to allow simulation of on/off-peak or hourly patterns as well as single periods. Based on the approach of Simonovic and Srinivasan [213] for planning Manitoba Hydro's reservoir operations, each monthly time-slice represents the aggregation of conditions during the specified period on each day. The starting storage in second and subsequent time-slices is the same as that ending the previous time-slice. Inflow and evaporation rates are assumed to be constant over the whole period and energy production constant over the slice. To reproduce the priority given to peak production, periods designated as such are simulated first, and while this is not chronologically correct, it is likely to follow actual practice.

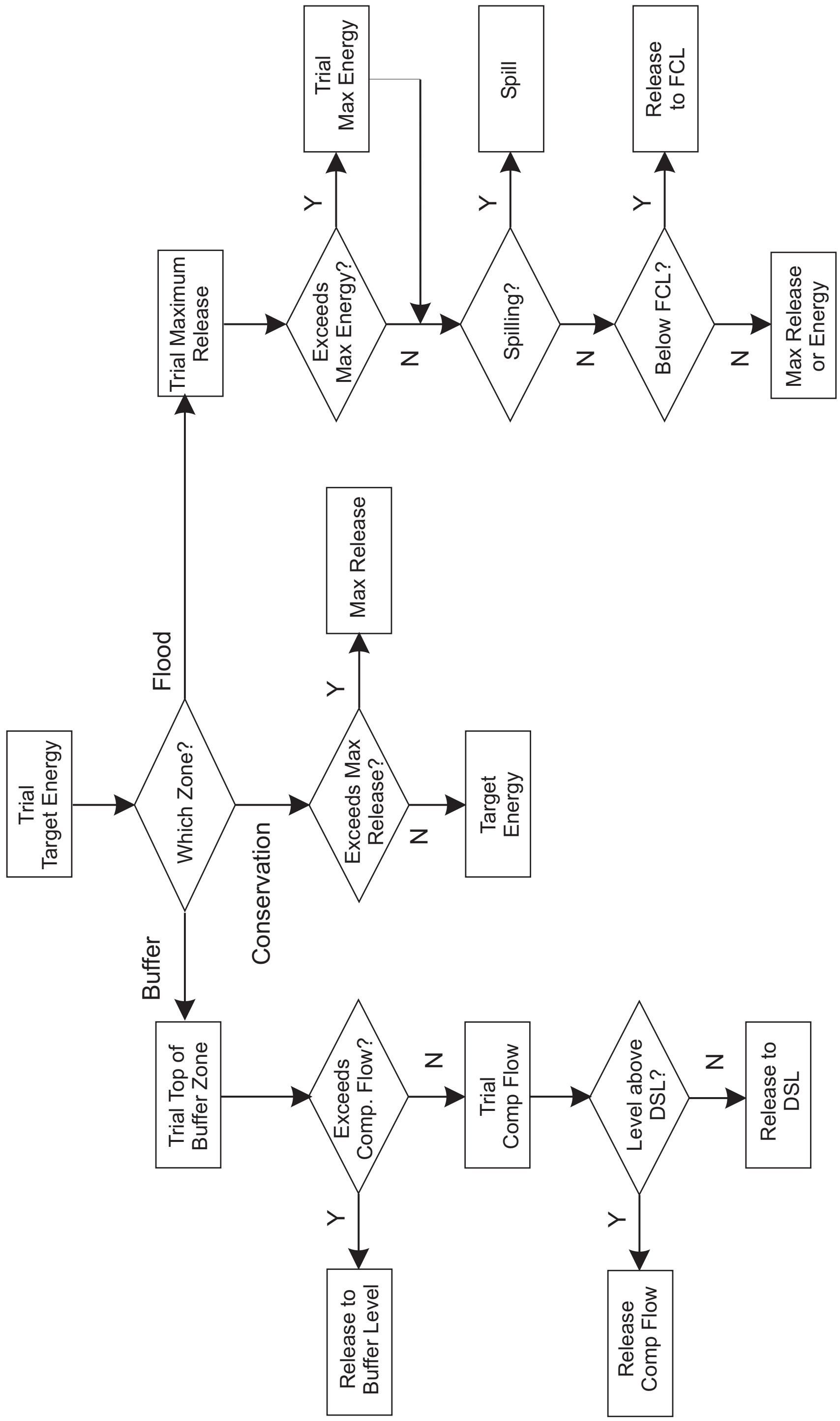
6.4.2 Target Storage Operation

The second technique determines the release necessary to meet the target level. If the release exceeds the penstock flow limits or the capacity of the turbines then the release is trialed at these lower levels. This will result in a water level that is higher than target, and in some cases may spill, in which case the spill routine is invoked. If the trial release is negative then the water level cannot be reached, and the lesser of either the compensation flow, or that necessary to reach the dead storage level, is released.

6.4.3 Spillage

Spillage is rather difficult to model and this may explain why it is neglected in many studies. However, with a monthly time step, most floods will be averaged out and so was deemed unnecessary to use a complex spillway accounting method.

The spillage routine firstly infers that spillage has occured if an end-of-period water level is found to be above the spillway crest. It is inadequate to assume that any water lying above the spillway crest has spilled, as the average head used in the computation is likely to be higher than that occurring in reality. For a constant power output the higher head would restrict the release through the turbines at capacity, and this will lead to a greater water level rise. To counter this effect, the spill routine assumes two stages: the first while the water is rising up to the spill crest, and the second when it is spilling. The first assumes average head between the start and spillway levels, and the second simply at the spillway. All inputs



DSL - Dead Storage Level; FCL - Flood Control Level; CF - Compensation Flow

Figure 6.8: Zonal pool routine

and outputs are converted into flow rates, and generally the lower head in the first period allows a higher turbine discharge rate. In the second period, excess flows are assumed to be spilled, with the ending water level at the spillway.

Gated spillways require a slightly different approach to free flow versions. Normally, the reservoir is kept at or below the normal pool level (NPL), and in the event of a flood, the gate is opened sufficiently for the level to remain as close as possible to the NPL. In effect, the NPL is the level above which water level cannot permanently rise, and as such will be equivalent to the spillway crest level in free flow spillways. Although such operation is not strictly correct, with gate discharge capacity varying with the reservoir level, it is acceptable as a monthly approximation.

6.4.4 Evaporation

Reservoir evaporation is accounted for using a similar evaporation model to that used with the water balance component. As the potential evaporation rate from open bodies is generally higher than from soil, the calculation is performed separately, and with the Priestley-Taylor method, different parameters can be set (*e.g.* a lower surface albedo of 0.08 as water absorbs more shortwave radiation than land). The amount estimated to leave the water surface is the net evaporation (*i.e.* less precipitation) and is calculated on the basis of the average water level during the month.

6.5 Electricity Market Model

Although one of the reservoir operation routines is designed to allow sub-period operation, the wholesale market is not considered suitable for this application. However, simulation of on/off-peak operation is possible.

Two basic types of purchase agreement are supported, allowing representation of must-take contracts and those covering specific quantities. Together with the different operational schemes, several possible combinations are available, although the target storage routine can only operate with single period must-take agreements, as in many respects the energy production could be seen as secondary in importance. As Figure 6.9 shows, the must-take agreements simply assign value to any production the plant may produce. For the alternative contract, over- and under-production attract user defined bonuses and penalties which act as a proxy for selling dump power and covering shortfall, respectively. Dump power is energy sold below the market value that otherwise would be lost through spillage, although it is only possible to generate if the system can absorb the extra energy.

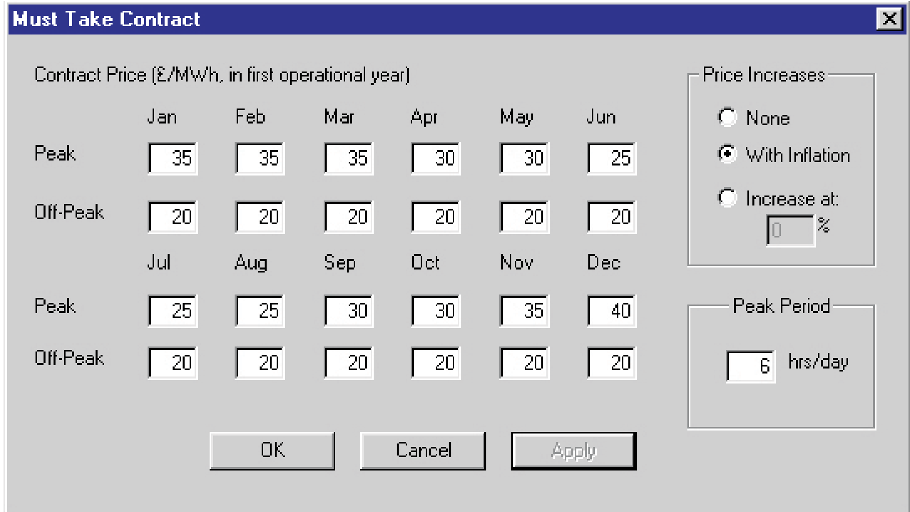


Figure 6.9: HydroCC must-take PPA dialog

Each operational method requires a dedicated scheduling dialog in which either end of month storage levels, or monthly energy targets can be specified. The latter also requires month-end flood control and buffer levels, and unit maintenance can be scheduled from either sheet. The scheduling sheets also provide access to the optimisation routines.

The genetic algorithm used for calibrating the water balance model is also applied to determine optimal operational strategy. Depending on the rule curve type, combinations of monthly storage levels or energy targets can be optimised to realise maximum benefit, and/or minimum spill. Additionally, firm power capability can be determined through a routine that finds the maximum energy level that can be guaranteed to a user defined reliability level, normally 99%.

6.6 Financial/Economic Model

The financial and economic details are entered on the same dialog (Figure 6.10). The economic lifetime of the station determines the length of the financial analysis, and is bounded by the length of available revenue. It is assumed that construction costs are spread evenly across all years of construction, and that borrowings and non-debt finance are drawn on the same basis. Interest is charged on the accumulated total debt, and the debt and interest are repaid in equal yearly installments.

Hydro schemes have low annual operational and maintenance (O&M) costs, which are typically in the region of 1-3% of the construction cost. O&M is split into fixed (£/MW) and variable (£/MWh) components, and the real values required in the dialog are increased annually with inflation.

Depreciation is required to correctly assess corporation tax liability as it is treated as a charge in the profit and loss account. The reducing balance depreciation allows for the salvage value by treating it as a profit received in the final year. Any tax due can be paid either in the year in which the profit is realised or the following one (standard UK practice).

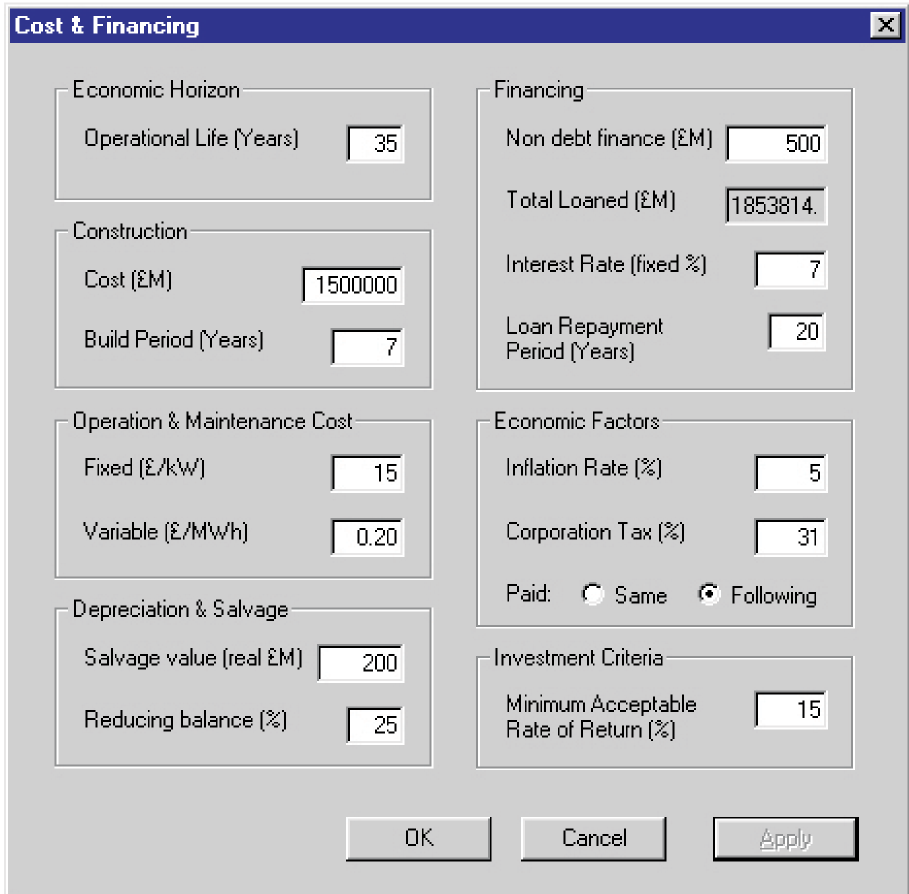


Figure 6.10: HydroCC finance and economic parameter dialog

The minimum acceptable rate of return (MARR) defines the real discount rate used in NPV and discounted payback calculations. The financial analysis covers a number of measures other than these. They include benefit-cost ratio, IRR, ROI, and range of unit cost measures including the simple IEA cost shown in Chapter 4. The starting point of the analysis is to determine the components of the annual nominal cash flow (NCF), inflating real values where necessary. The NCF is then deflated so that other measures can be determined. The cash flows and their components are output to text files for further analysis. Other measures calculated include annual coverage ratios and internal rate of return which allow for multiple IRRs which can occur with net cash flows that change sign more than once (see [146]).

6.7 Ancillary Components

A number of support features are contained within the software to allow its successful operation.

6.7.1 Genetic Algorithm

Used in the hydrological model to optimise parameters, and in the reservoir model to optimise reservoir operating patterns, the Genetic Algorithm is a highly flexible search and optimisation tool. Its operation is based on natural selection and genetic evolution, and can be used where exhaustive searches of large search spaces are impractical. Apart from the two applications mentioned here, genetic algorithms have been used in many problems including load flow determination and in forecasting future electricity supply mix [214].

A GA uses a fixed size ‘population’ of possible solutions (chromosomes) consisting of a number of parameters (genes) that describe the solution. Each solution may be evaluated for its fitness in meeting a particular goal, which is normally maximisation (or minimisation) of an objective or fitness function. The initial population can be created randomly, and evolves towards greater fitness with each generation, by the application of a variety of genetic operators: *selection*, *crossover* and *mutation*. The operation of a simple GA is as follows:

1. Initialise population
2. Evaluate the fitness of each population member
3. Selection - on the basis of individual relative fitness determining the probability of selection, select two parent chromosomes
4. Crossover - the parents ‘breed’ and create offspring
5. Mutation - mutate offspring on the basis of a mutation probability
6. Accept - evaluate the new population members, and add to the overall population in place of the worst individuals
7. Return the best individual if the solution is acceptable or the maximum number of generations are reached, otherwise return to 3.

The GA implemented for this application uses proportional (or roulette wheel) selection, two-point crossover (where information is exchanged between two randomly chosen points on the chromosome), and non-uniform mutation which tends to reduce the degree of mutation as the population develops. The values deemed suitable for the crossover and mutation probabilities are chosen separately for each problem and tend to require experimentation to achieve robust solutions.

The new solutions created by crossover and mutation tends to allow the solution to proceed to the global optimum, rather than local optima which often occurs with hill-climbing and other search techniques. However, in common with other finite search procedures, GAs do introduce sampling errors and possible non-optimal solutions. Further discussion of GAs can be found in Michalewicz [215] and others.

The genetic algorithm implemented is based on the simple scheme described by Michalewicz [215], and applied with some alteration by Silverton [214]. Full use of object oriented techniques and features were made to allow the scheme to cope with different types of model and variable chromosome length and population size.

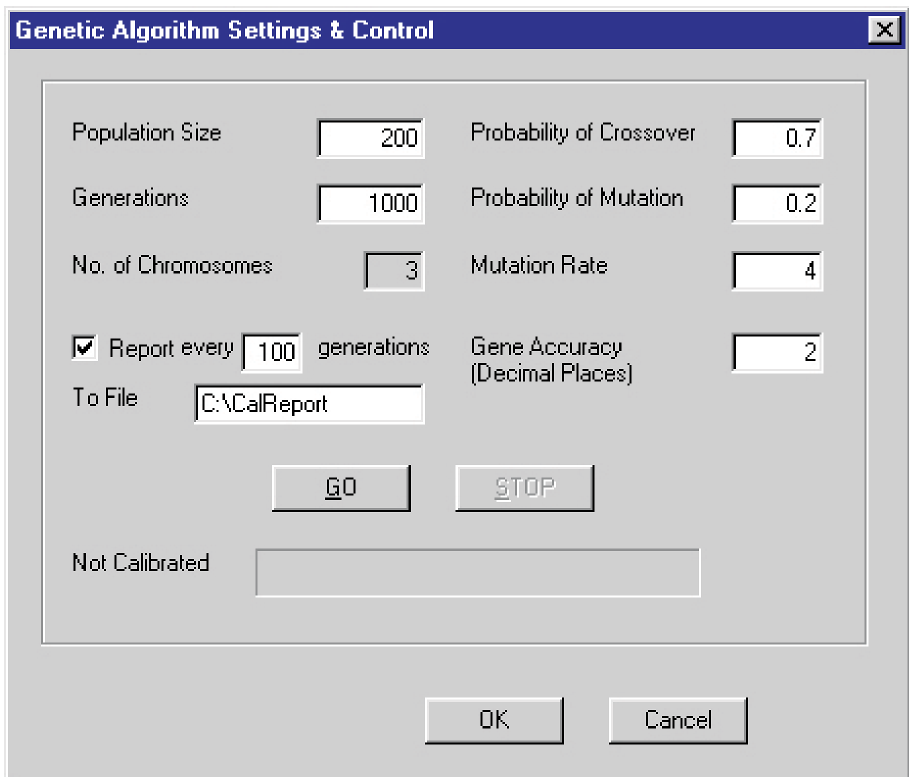


Figure 6.11: Genetic algorithm control dialog

6.7.2 Statistical Module

Many of the modules rely on statistical measures for decision making, or for summarising data output. As Visual C++ is not issued with anything other than the most simple statistical routines, it was necessary to develop a suite of techniques. Partly based on standard C programming routines [216], the routines are designed to handle arrays of variable length or sections of them. The routines include mean and variance calculations as well as more specialised routines to handle correlation, coefficient of determination and cumulative frequency.

6.8 Program Operation

6.8.1 Simulation Options

Program operation is selected from the simulation settings dialog (Figure 6.12) accessed from the menu (Run | Settings) or toolbar. To be able to run each component a minimum level of acceptable data must be entered. The program performs a check on each component and ascertains their status, and if a particular module is incapable of being run, then it and those that depend on its results are disabled. A test log can be viewed from the dialog. The simulation can involve any module preceding the disabled ones, and in the instance where all components are deemed acceptable then the user can select the end point.

Either single or multiple (risk analysis) climate series can be selected for use. The climate mode can be selected by the radio buttons, and includes use of base climate data, arbitrary uniform scenarios or GCM scenarios. Arbitrary scenarios can be created by combining changes in precipitation and temperature (or PET) using the slide bars. Any GCM scenarios held in memory can be selected from the appropriate list box. Although the settings facilitate the application of scenario analysis and (pseudo-) risk analysis, sensitivity analysis must be carried out manually by altering the required values (*e.g.* construction cost) manually and running the simulation once again. Simulations can be run from the toolbar or menu.

6.8.2 Results Generation

The simulations settings dialog asks the user for a target directory in which all simulation results are to be deposited. Creating the directory if necessary, the directory also contains a results summary file which allows the user to rapidly compare different runs. Alternatively, a selection of the results can be posted to a series of property sheets that appear following the completion of the run (if the relevant control on the settings sheet has been checked). The results displayed include most of the financial measures, as well as derived statistical parameters of climatic variables, PET, river flows and energy production. No graphical facility is included in the software, as the variety of the data precludes effective display, and greater benefit is gained by making results compatible with the graphical tools available in spreadsheet packages.

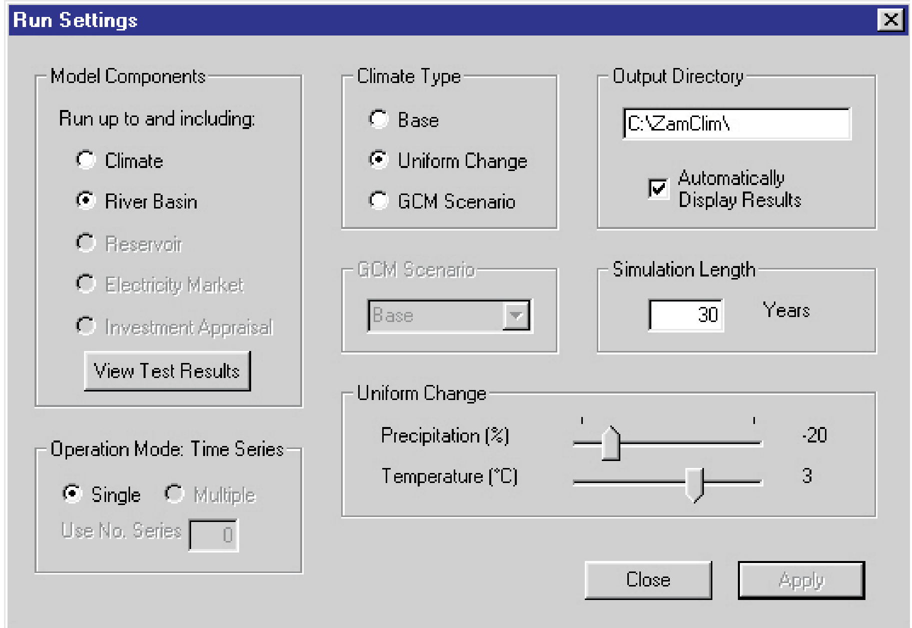


Figure 6.12: Simulation settings dialog

6.9 Summary

This chapter provides an introduction to the HydroCC investment appraisal software, and describes the basic structure and functioning of the constituent parts. The climate component enables efficient data manipulation, application of climate change scenarios and the creation of synthetic series of precipitation and temperature. The WatBal hydrological model provides a simple and robust means of simulating rainfall runoff processes with a minimal data requirement. The reservoir model addresses the criticisms levelled at previous climate change studies by incorporating full reservoir storage accounting, variable hydraulic head, evaporation and spillage. The market module permits simulation of a number of different contract structures and scheduling schemes. The financial and economic routines used enable a realistic and acceptable analysis of many standard investment measures. All or part of the investment appraisal process may be simulated and sensitivity, scenario and basic risk analysis performed.

Chapter 7

Case Study: Batoka Gorge

This chapter introduces the Batoka Gorge hydropower scheme and presents its location, hydrology and specifications. Specific data issues are considered along with the testing of the 'HydroCC' software. Base simulations of the scheme's operation and performance are compared with arbitrary and GCM derived climate scenarios for the purposes of examining the schemes sensitivity to climatic change, before the execution of a risk analysis.

7.1 The Zambezi River Basin

The Zambezi River is the fourth longest in Africa. It rises in the Central African Plateau in eastern Angola and flows over 2,600 km to the Indian Ocean. The basin lies south of the Equator between 12° and 20°, drains an area of over 1,350,000 km^2 and is shared by eight nations (Figure 7.1). Over 38 million people live within the basin, of which 54% live in Zambia or Zimbabwe.

The basin is split into three areas. The *Upper* Zambezi contains the headwaters of the river in northeast Angola, and ends at the Victoria Falls on the Zambia-Zimbabwe border. From its source the river travels southwards and is joined by several tributaries, including the Chobe, at the confluence of which, it turns eastwards towards the Falls. Flow over the Falls averages 1,237 m^3/s.

The *Middle* Zambezi stretches from the Victoria Falls to the Cahora Bassa dam in Mozambique, dropping 600 m in the process. The river passes Batoka and Devil's Gorges and is dammed at Kariba. Several tributaries join the river in this section including the Kafue which boosts the average flow to 2,700 m^3/s [217].

The *Lower* section extends to the delta in southern Mozambique and has a catchment area of 282,000 km^2. It receives around 1725mm of precipitation each year

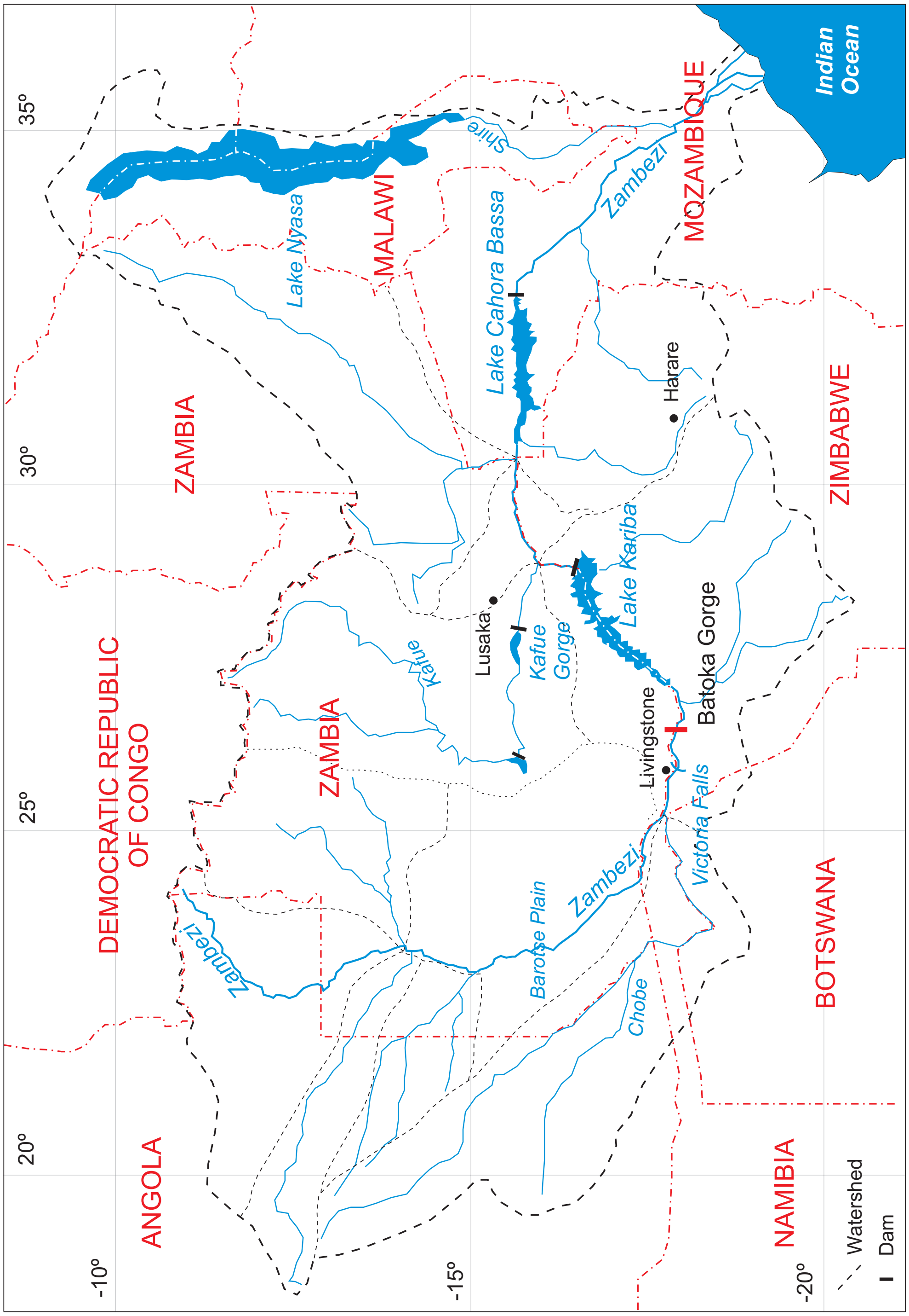


Figure 7.1: Zambezi River Basin (Redrawn from Zambezi River Authority (ZRA) map)

contributing to an average flow of 3,500 m^3/s at the delta [217].

7.1.1 Climate and Hydrology

The basin has a tropical climate, with a rainy season lasting from November to April and peak temperatures occurring in October. Rainfall is higher in the northern part of the basin, and falls from 1500 mm to around 700 mm in the south. Mean temperatures are in the region of 18-24°C, and extremes of 5 and over 30°C. The warm sunny conditions create high insolation and a correspondingly high evaporation rate. Data indicates evaporation of 1800-2200 mm annually, with monthly totals of 200 mm in October to March and 125 mm in June/July.

Hydrologically the Upper basin is very complex due to intermittent streams and the influence of the Barotse Plain and Chobe swamps [218]. The Barotse Plain in Zambia is a seasonal swamp covering some 7,500 km^2, and plays a major role in regulating flood waters in the upper basin. It is estimated that during the major flood of 1958 some 17 billion cubic metres (BCM) of flood water was stored in Barotse, equivalent to half the average annual volumetric flow over Victoria Falls [219]. At flood the Zambezi backs up the Chobe tributary and fills the upstream swamps, which return the water once flows have reduced. In addition to flood control the periodic swamp-filling acts to trap sediment and allow significant evaporative loss. Only a third of the precipitation in the upper basin reaches Victoria Falls, the rest is lost to evaporation [114].

River flow has been gauged for over 105 years at Livingstone (now Masunda) and the river flow statistics reflect the complex hydrology. As Figure 7.2 shows, peak runoff arrives between early March and late May with the average around mid-April. Minimum flows normally occur in early November. The size of the floods has a bearing on the timing of their arrival, with larger flows arriving earlier as smaller peaks are attenuated by Barotse and Chobe.

The hydrological complexity of the Upper basin is reflected in the local runoff coefficients. In the headwaters, unit runoff of 270 mm is produced from 1500 mm of rainfall, but in the Chobe sub-basin only 20-25mm of runoff occurs from 600 mm [218].

7.1.2 Hydroelectric Development

The large river flows means that the Zambezi has enormous hydroelectric potential, most of which is situated in the middle and lower sections (Figure 7.3). The first scheme developed was the run-of-river (RoR) Victoria Falls plant, which harnessed the drop at the falls to create the head. Initially rated at 8 MW, the scheme was

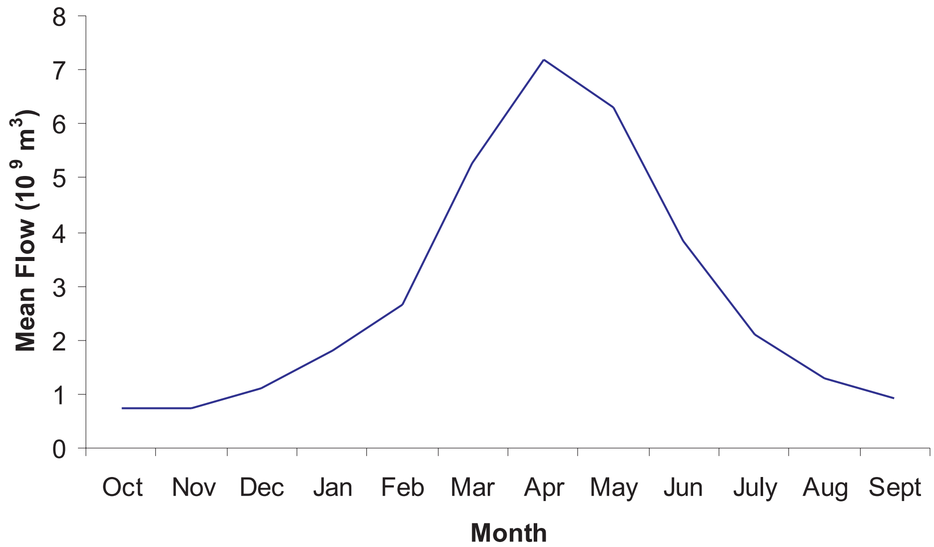


Figure 7.2: Mean monthly flows at Victoria Falls

upgraded in 1968 and 1972 to its current 108 MW. The first major scheme was the Kariba Dam, built primarily to supply the Zambian Copperbelt, with the southern 666 MW station commissioned in 1960. This was followed by the commissioning of the 2075 MW Cahora Bassa scheme in 1975, and both Kafue Gorge (900 MW) and Kariba North (600 MW) in 1977. Current installed capacity including stations on the Shire River in Malawi is 4,684 MW producing approximately 33,000 GWh per year

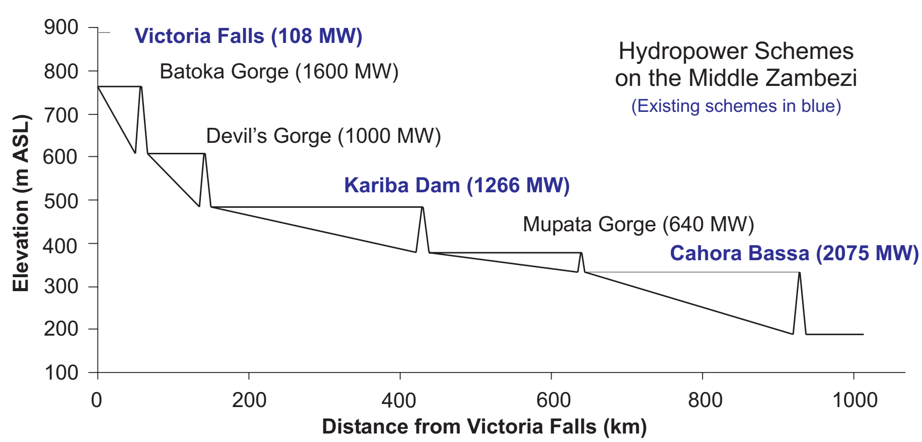


Figure 7.3: Hydroelectric facilities on the Middle Zambezi River [220]

The middle Zambezi is also the focus for several potential new build schemes which include sites at Batoka Gorge and Devil's Gorge. These schemes boast potential capacities of 1600 MW and 1000 MW, respectively. A combination of upgrades to existing stations and the new build schemes could create an extra 13,300 MW of capacity. The Kafue Lower scheme, the first of the new capacity, is scheduled to be commissioned in 2004, followed by the 1200 MW extension to Cahora Bassa due in 2005.

The operational planning for the basin is the responsibility of the Zambezi River Authority (ZRA) which came into being in 1987 following Acts of Parliament in both Zambia and Zimbabwe. It replaced the Central Africa Power Corporation (CAPC) that had been responsible for Kariba since 1963. The creation of the ZRA was an early example of improving regional cooperation, which is now carried carried out through the Southern African Development Community (SADC).

7.1.3 Batoka Gorge Scheme

Several studies have examined the possibility of building a dam at Batoka Gorge which lies 56 km downstream from the Victoria Falls. A 1981 report by Mott MacDonald and Sir Alexander Gibb proposed a double curvature arch dam. Pre-feasibility studies identified 18 possible combinations for the scheme, differing in areas such as dam type, number and location of power houses and number of penstocks. The options were compared on a least cost basis, and the current specification was determined to be the best, prompting a full feasibility study (FS).

The feasibility study was undertaken by the Batoka Joint Venture Consultants (BJVC), consisting of Knight Piesold Ltd, Lahmeyer GmbH and Electrowatt Engineering Ltd. Carried out over a 21 month period prior to September 1993, the study examined the technical, economic and environmental aspects of building a 181 metre high, roller compacted concrete gravity arch dam [221]. As Figure 7.4 shows, the scheme features two underground power houses (one on each side of the gorge), each with four 200 MW Francis turbines, giving a total capacity of 1600 MW. The dam would possess a radial gated spillway designed to pass an expected maximum flood of 20,000 m^3/s.

The full supply level (FSL) lies at 762m above sea level (ASL), and 4 metres below the 766m long dam crest which carries a road between the two countries (Figure 7.5). The volume at FSL is $1,680 \times 10^6 m^3$, with live storage representing a third of that. The relatively small active storage (around one fortieth of Lake Kariba's 70 km^3) means that Batoka is designed to be operated as a run of river scheme, providing minimal flood storage.

The operating aim of the scheme is to maximise firm power delivery on a system level. To this effect Batoka is designed to operate in tandem with Kariba, such that, when flows are high, Batoka will generate thus allowing more effective use of the

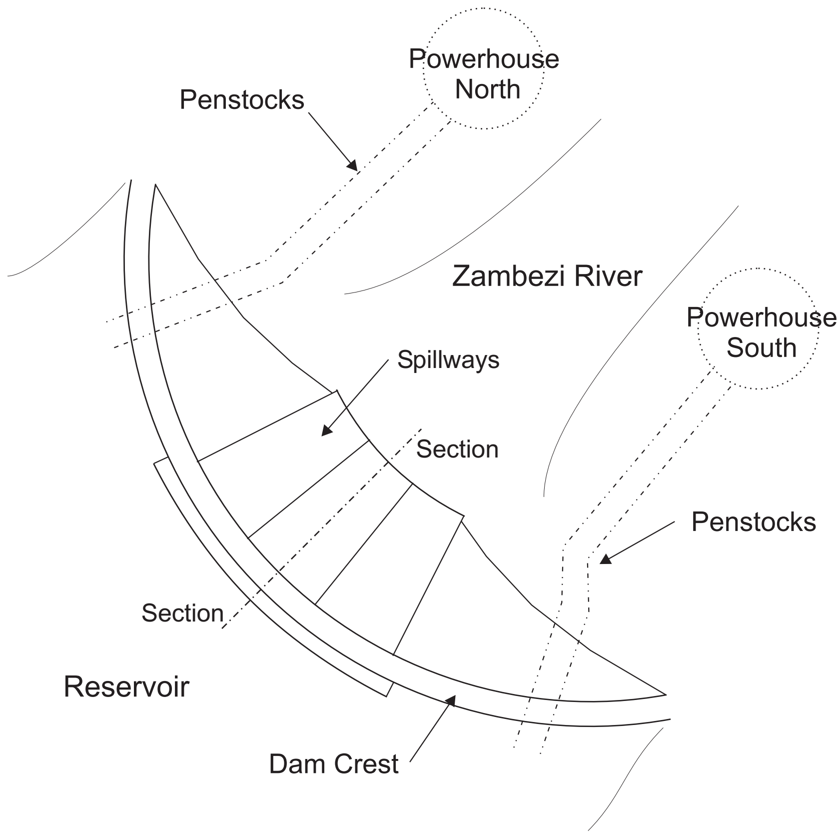


Figure 7.4: Schematic plan view of Batoka Scheme

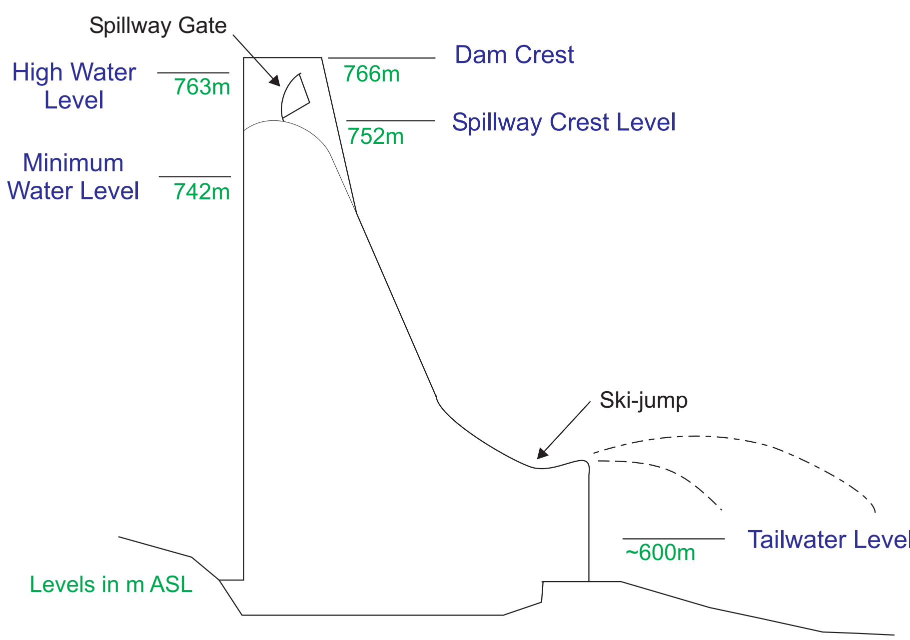


Figure 7.5: Spillway section schematic

storage in Kariba.

7.1.4 Existing Climate Change Studies

As Batoka lies upstream from Kariba, and there are no impoundments of note in the Upper basin, the flow is essentially natural. This makes it a good candidate for climate change investigation. However, most investigations of water resources impacts on the Zambezi have focussed on the Kariba impoundment, mainly because it is already in operation and of its importance in regional energy production. Salewicz [222] used the CLIRUN water balance model, from which WatBal is descended, to generate time series of inflows to Kariba, where the release rules developed by Gandolfi and Salewicz [219] were employed to estimate energy production.

Batoka Gorge featured along with Kariba in the study by Reibsame *et al* [114]. Relying on the river flow at Victoria Falls to indicate hydrological conditions, the study used a deterministic rainfall-runoff model, driven by monthly values of spatially averaged temperature and precipitation, to generate river flow estimates. These provided the input to the Massachusetts Institute of Technology River Basin Simulation model (MITSIM) [223] which determined the changes in hydropower production and other water resources. MITSIM requires monthly flow duration curves in order to simulate reservoir operation. Four GCM scenarios were applied to the observed climate series: GISS, GFDL, UKMO and a transient GISS run equating to conditions in 2030. Whittington and Gundry use these results as part of a wider examination of hydroelectric resources in Sub-Saharan Africa [137].

The findings from each of these studies are used to corroborate and compare the results produced during the case study.

7.2 Modelling Batoka Gorge

This section examines the means of creating and using data for the study.

7.2.1 Climatological Data

To allow estimates of the net evaporation from the Batoka and Kariba reservoirs, the Batoka feasibility study used rainfall and evaporation pan data provided by the Zambian Meteorological Department. This study will make use of data contained in the global gridded time series dataset developed by New *et al* [196]. Available from the Climatic Research Unit, the data provides coverage on a $0.5° \times 0.5°$ grid for the 95 years up to 1996, and as Table 7.1 shows, covers several primary and secondary variables.

Primary	Unit	Secondary	Unit
Precipitation	mm/day	Cloud Cover	oktas
Mean Temperature	°C	Vapour Pressure	kPa
Diurnal Temperature Range	°C	Wet-day frequency	days

Table 7.1: Primary and secondary climate variables in the CRU dataset [196]

In addition to precipitation, the data facilitates the use of both the Priestley-Taylor and Hargreaves PET methods. The latter uses both mean and diurnal temperatures, while the former will use mean temperature, vapour pressure and cloud cover. With the exception of cloud cover all data is used in its original form. As the net radiation routine in this Priestley-Taylor formulation uses mean monthly sunshine hours to indicate the degree of cloudiness, the cloud cover measure required conversion. The cloud measure given in the database uses 'oktas' which refer to the number of eighths of the sky obscured by cloud. The desired form is found by converting these to percentage cover, and multiplying by the potential sunshine hours (*i.e.* day length).

The dataset is arranged such that each variable has one file for each year. However, each file contains around 15 megabytes of information that must be held in memory if the data is to be used. This necessitated the creation of software to distill data for a given area from each data file. The software creates a smaller Cartesian grid for each month of each year in a form that is spreadsheet compatible, such that further processing (*e.g.* spatial aggregation) can occur. Each file takes approximately 2-3 minutes to distill, so in order to reduce the machine minding on the part of the user, the software allows a sequence of years to be distilled at one time.

Figure 7.6 shows the mask constructed to allow only data points lying within the catchment of the Upper basin to be included in the spatial aggregation. A grid was overlaid on a map of the basin and sub-basins, and grid-squares were accepted as contributing to the basin if at least half of their area was judged to lie within it. Once the mask was applied, the spatially averaged monthly climate time series was constructed. All grid squares within the catchment were equally weighted, although it was recognised that significant spatial differences occur in almost all months. The monthly data was then placed in a form suitable for HydroCC.

Climate Data Validation

Climate data for the standard 1961 to 1990 period was extracted from the database, and aggregated for the upper basin.

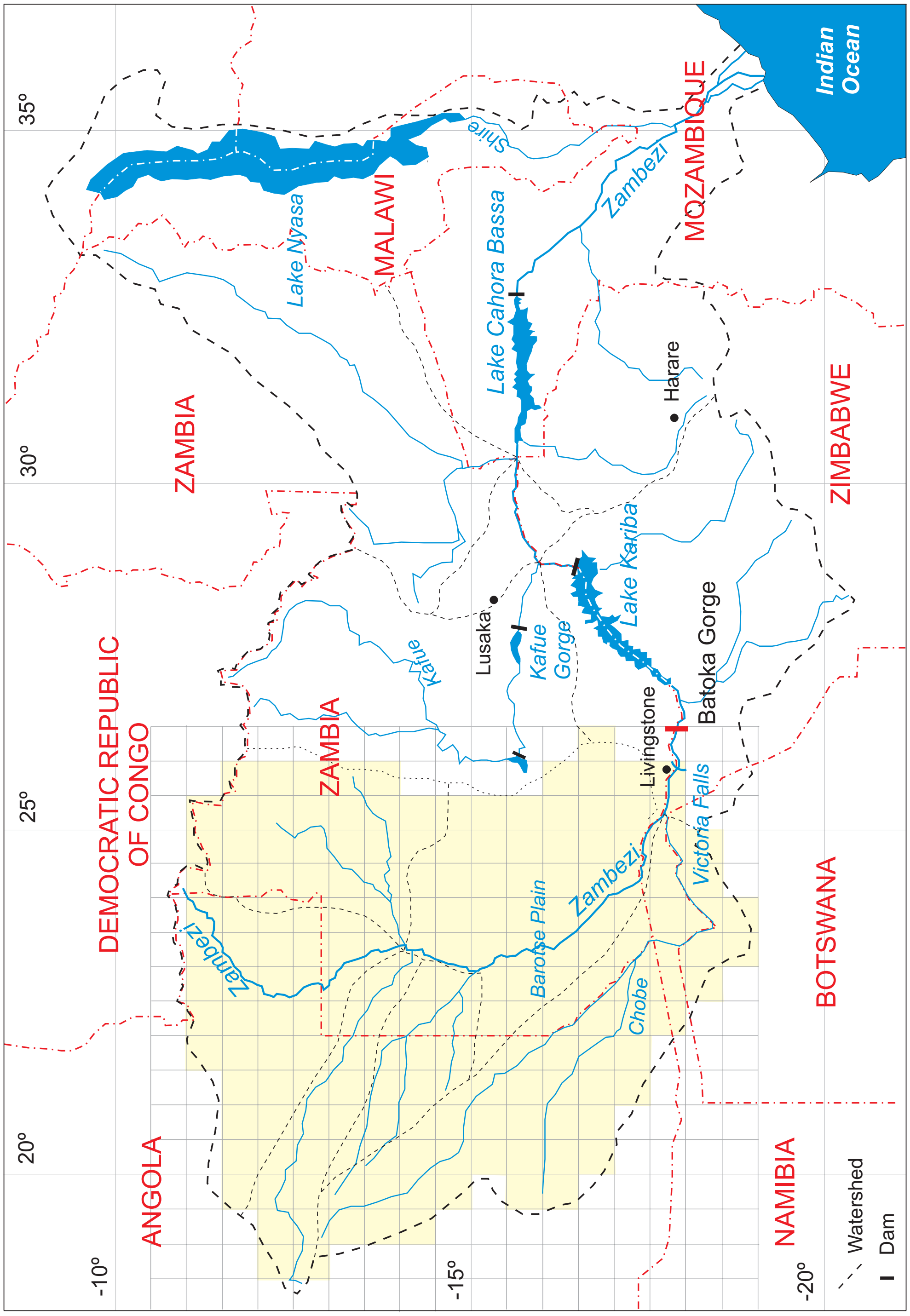


Figure 7.6: Zambezi Basin and aggregation mask

As Figure 7.7 indicates, both the Hargreaves and Priestley-Taylor methods result in similar monthly PET patterns, although on average Hargreaves estimates are 13% lower. The higher values for the Priestley-Taylor method could be accounted for by the designation of the basin as arid, as the relative humidity in the month of highest PET (October) is less than 60% [212]. As such, a higher value of β is applied (1.74 rather than 1.26).

The marked difference between PET and precipitation patterns illustrates the complexity of the hydrology, and indicates the aridity of the basin. The ratio of PET to precipitation is 2.25 for Priestley-Taylor and 1.96 for Hargreaves, and these compare well with the ratio of 2.5 found by Reibsame *et al* [114]. Given that the latter study used PET and precipitation estimates for the entire Zambezi Basin and given the tendency for lower precipitation in the southern part of the basin, which are not included in the present estimates, then the slightly lower ratios calculated for this application seem reasonable. Given the better match between the Priestley-Taylor method, and its inherently more realistic representation, only this method features further in the study.

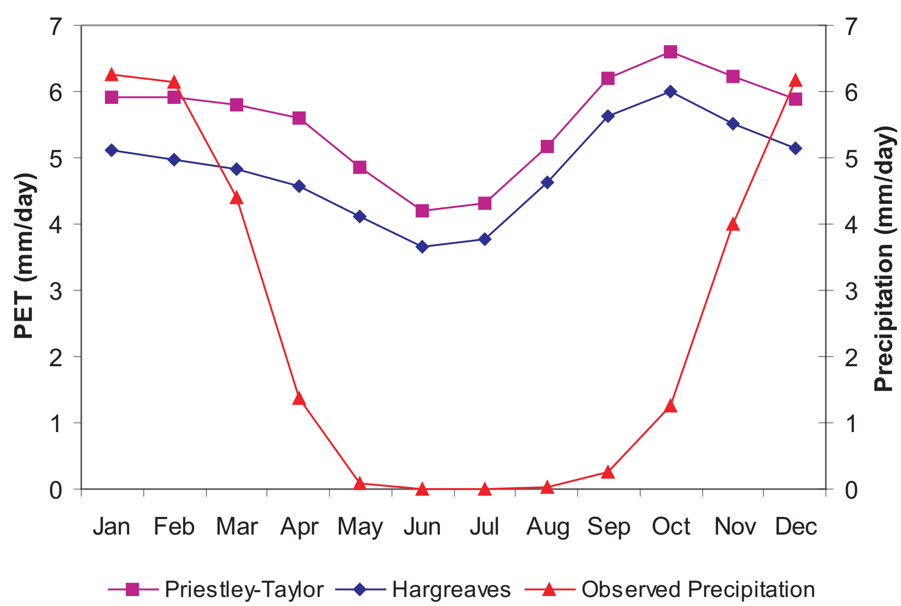


Figure 7.7: Monthly PET estimates from Hargreaves and Priestley-Taylor methods

7.2.2 Hydrological Model Calibration and Performance

To calibrate the hydrological model, observed climate data and river flow data are necessary. The river flow record at Victoria Falls is suitable for this purpose, as the

Batoka site lies relatively close to Victoria Falls and there is no notable inflow from the additional catchment area.

Both the climate and river flow data are available between 1908 and 1992, although the period selected for calibration and eventual operation is the standard 30 year period from 1961 to 1990. This allows reasonable split sample testing with the calibration and validation periods each of 15 years.

Despite the inherent complexity of the Upper basin hydrology, the analysis used the lumped parameter model, in part to determine the suitability of the simple approach. As there is no notable snowfall in the basin the snowmelt model was not required. Following the practice of Yates and others the baseflow value was set to the 95% exceedance flow value corresponding to 0.04 mm/day.

Although the overall catchment area for the project is 505,000 km^2, the Chobe tributary is reported to contribute less than 135 $m^/s$ of runoff [218]. As such, and following the practice of Salewicz [222], the contribution from Chobe was ignored, reducing the effective catchment area to 360,505 km^2.

Search Methods

To enable the assessment of the genetic algorithm's suitability for the purposes of calibration an exhaustive search was first carried out. The sub-surface runoff exponent (κ) was set at 2, while the four other parameters were optimised. For the exhaustive search, reasonably coarse increments of parameter values necessitated over 1.2 million runs of the water balance model, representing somewhere in the region of six hours computation on a relatively fast PC (Intel Pentium 233MHz).

With the GA using a population of 200 parameter sets and evolving over 500 generations, the optimal parameter set was found in 40 minutes. Direct comparison of the results of the two methods was limited by the coarseness of the exhaustive search parameter increments, although similar optimal parameter values and maximum fitness measures were noted. Subsequent runs of the GA found similar solutions, confirming that, on average, the method is robust and avoids local optima. Therefore the GA appears to be suitable for generating optimal values for the water balance model.

Optimal Performance

Despite the relatively high correlation coefficient (~ 0.80) and good representation of the dry season low flows, the flood flows were unacceptably low. Manual parameter adjustment was necessary to improve the seasonal variation and the resulting parameters are given below:

- sub-surface coefficient $\alpha = 2.5$
- surface exponent $\varepsilon = 3.5$
- sub-surface exponent $\kappa = 2$
- maximum soil moisture $S_{max} = 40$ mm
- initial relative soil storage = 0.25

The chosen parameter values were analysed for their contribution to error in forecast flows, and it was found that over a range of $\pm$ 10% of optimal value, changes in parameters introduced near linear changes in mean annual flow. As expected, κ produced the greatest variation (13%) with initial storage offering less than 0.3%. The sensitivity of annual flows are shown in Appendix A, Figure A.1.

Although these values resulted in a visually improved flow representation and a simulated mean annual flow within 0.1% of the observed value, the adjustment lowered the correlation measures. While this is unfortunate, existing research stresses the importance of seasonal representation over mathematical fit [107, 168]. The resulting statistical measures are listed in Table 7.2. The calibration period is found to produce higher correlation measures although the validation period appears to offer a closer volumetric match. The low flow performance is maintained as the time series of flows indicates (Figure A.2, Appendix A).

	Calibration 1961-1975	Validation 1976-1990	Whole Period 1961-1990
Nash-Sutcliffe Criterion	0.59	0.47	0.55
Correlation Coefficient	0.61	0.49	0.56
Mean Absolute Error (mm/month)	1.00	0.98	0.01

Table 7.2: WatBal calibration and validation statistics

As Figure 7.8 shows, even with the manual adjustment, the simulated flow pattern shows an earlier and lower peak flow, resulting a slightly longer flood season. This is due to the limitations of a model with relatively few parameters in simulating significant seasonality, a fact noted previously by Yates and Strzepek [139]. In addition, the Barotse and Chobe seasonal swamps significantly increase the storage available in the basin, which is a feature not considered in the WatBal model. The temporary storage of early high flows will tend to reduce flows in January and February, and concentrate the flood in April and May, before its rapid decline. Without the storage of early high flows in the swamps the simulated January and

February flows are higher and consequently the peak flows are earlier and last longer, as the slower decline demonstrates. The effect would be similar if the model were applied to a snow dominated catchment without accounting for snow accumulation.

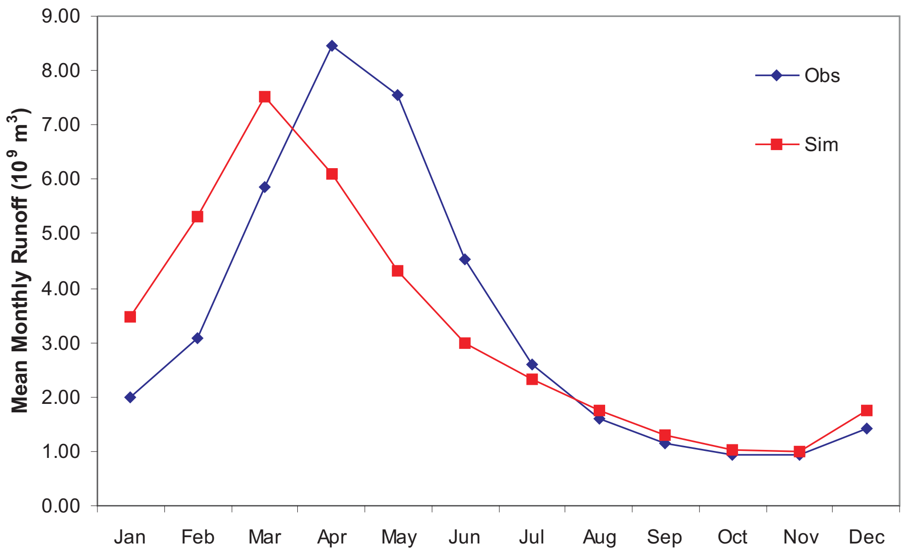


Figure 7.8: Comparison of monthly observed and simulated river flows

The low correlation coefficients could preclude the model from use in this basin, as could the poor representation of seasonal flows. Gleick's [167] approach of creating a semi-distributed model by dividing the basin into two or more sub-catchments as a means of improving seasonal performance was considered. However, the problem lies not with aggregating different climate representations, rather in the fundamental structure of the model, and therefore effort in that direction was considered wasteful. Incorporation of a special storage component would be possible but as this feature is fairly specific to the Upper Zambezi, the additional effort would be unwarranted. Given that some water resources projects have been developed using models with correlation coefficients lower than that found here [224], and that benefit will accrue even with relatively poor model performance, the hydrological model was accepted as suitable, with reservation.

7.2.3 Hydro Station

Annual production from Batoka is expected to be 9,093 GWh [221], interpreted by Reibsame *et al* to represent equal monthly targets of 757 GWh [114], and this target was followed in the absence of addition information. All turbines are assumed to be available and operating at 86% efficiency. Although tailwater levels may vary between 590 and 607.5 m ASL depending on discharge, a fixed value of 605 m was assumed to match the higher flow months. Reservoir storage is initially set halfway between the full supply level (762 m)and minimum water level (742 m). As no information was available regarding the use of flood control or buffer zones, none were allocated.

As Figure 7.9 shows, releases and hence energy production closely follow inflows indicating that the reservoir model is operating correctly as a run-of-river plant. The proportionately greater increase in power output during the wet season is due to the higher hydraulic head as the reservoir level is maintained at full supply and excess flows spilled. The reservoir is drawn down during July to December in order to maintain production. The average plant load factor is 67%, although this masks a large seasonal variation of nearly 89% during the January to July wet season and only 36% during the dry season.

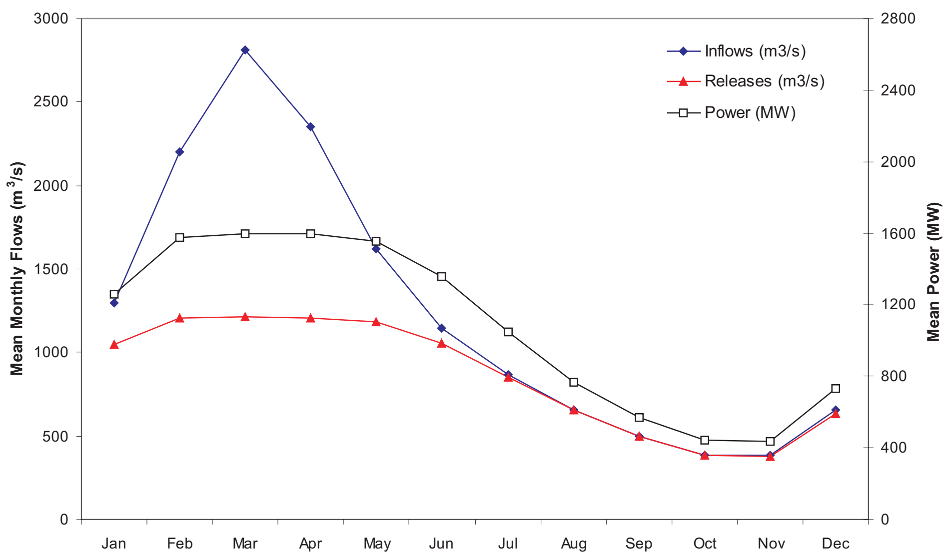


Figure 7.9: Monthly production, releases and river flows

The model over-predicts annual production by some 3% over the 30 year period, due to the ability of the station to take advantage of the longer simulated flood, and more efficient energy conversion with higher average water levels. Once again there is a marked seasonal difference in terms of the ability of the station to meet target power, with a 37% surplus and a 45% deficit in wet and dry periods, respectively. The same pattern is found by Reibsame *et al* who note lower values of production: annual (78%), wet (97%) and dry season (53%). The agreement between the dry season performance indicates the success of the WatBal model in simulating low flows.

7.2.4 Electricity Market and Project Economics

Market Conditions

The market and financial analysis of Batoka Gorge is made more complex as it involves both Zambia and Zimbabwe. The Batoka FS estimated that growth in the two countries would average 3% per year from 1993 to 2010, although they note that their estimate is conservative relative to those of both ZESCO and ZESA the Zambian and Zimbawean utilities. Zambia is forecast to have a continuing electricity surplus whilst Zimbabwe expects shortages particularly once power purchase contracts from Mozambique expire in 2003.

Electricity prices in both countries were below the cost of production and the study predicted that action was necessary to bring prices in line with costs, to around 3 US c/kWh by 1997. With Zimbabwe effectively purchasing most of the output of Batoka and the surplus exported to South Africa at 0.5 US c/kWh, significant benefits could accrue to both parties. The analysis assumed inflation of 5% and a real discount rate of 10%.

Project Costs

The basic cost of the project was estimated at US$1.15 billion, and as Table 7.3 shows civil works account for 58% of the total (a more detailed breakdown can be found in Table A.1 in Appendix A). In addition, interest on construction and the cost of transmission lines must be included. The feasibility study found that with a total project cost of some $1.5 billion, the unit cost of electricity from Batoka was 1.79 c/kWh which is lower than all other potential projects in the Zambezi basin other than the Kafue Lower project.

Item	US$ million
Civil Works	671,540
Mechanical Equipment and Hydraulic Steel Structure	220,396
Electrical Works	171,030
Total Construction Cost	1,062,966
Other Costs	90,352
Basic Cost	1,153,318

Table 7.3: Batoka Dam cost summary [221]

Operation and maintenance costs including those for transmission are estimated to total around $18 million annually. With a dam O&M of 0.8% of capital cost this is equivalent to an annual fixed capacity charge of $9.20/kW.

Project Financing

The whole spectrum of financing structures were considered for Batoka. Non-aid development was found to be impossible as the $210 million a year cost during construction was beyond the budget capabilities of either of the countries, representing as it did, almost one quarter of their combined energy sector expenditure at the time of the study (at exchange rates applying at the time). A build-operate-transfer (BOT) scheme was also considered infeasible due to the poor political and economic situation together with the welfare aspects of likely higher tariffs.

Foreign aid is a reasonable option, and would be likely to be granted to Zimbabwe as the project goal of reducing energy importation makes it a priority. Zimbabwe's good credit worthiness and history of foreign financing ($382 million in 1990 alone) would also improve the chances of success. Zambia would be less likely to get aid as the project is not a development priority.

Two basic financing schemes were examined, the first funded entirely by loans and the second with 50% grant aid. International loans were assumed to be offered at 7% interest with 7 year grace and 13 year repayment periods. A similar system to the second option is considered here.

For the purposes of this study the overall cost was taken to be $1,150 million with a non-repayable foreign aid grant contributing $800 million. While this figure is in excess of 50% of the dam construction cost alone, it is not unreasonable when compared to the total cost of the scheme which includes transmission line construction and financing costs. The project is assumed to have tax free status, and inflation is a constant 5%, although this is low given recent Zimbabwean inflation rates of 20-30%. The project lifetime is assumed to be 30 years, although the feasibility study uses the year 2040 for the end of the project. The FS estimates the salvage value of the plant to be $529 million in nominal terms. In real terms and with project termination in 2032 a salvage value of $90 million is reasonable.

The basic results from the model correlate well with the findings of the feasibility study. The internal rate of return produced by the HydroCC simulation was 11% compared to 11.5% for the feasibility study, with NPV measures giving $98 million versus $121.3 million. The benefit-cost ratio is also similar with a value of 1.10 rather than 1.21. The IEA unit cost suggested by HydroCC is 1.52 c/kWh, whilst the FS quotes a production cost of 1.46 c/kWh. The discrepancies between the calculated base values and those found in the original FS study could be attributed to different accounting treatments or definitions of measures.

7.2.5 Base Scenario

Overall, the HydroCC model gives results that compare reasonably well with previous studies. To facilitate comparison with the results of climate change experiments selected measures are given in Tables 7.4 and 7.5, and these will be referred to as the 'Base' scenario.

Monthly Value	Mean	Std. Dev.
Precipitation (mm)	74.6	78.9
Temperature (°C)	21.9	2.7
Potential Evapotranspiration (mm)	169.4	23
Runoff ($10^9 m^3$)	3.21	2.27
Relative Soil Moisture Depth	0.27	0.10
Energy Production (GWh)	780.3	350.3
Releases ($10^9 m^3$)	2.24	0.90
Spill Volume ($10^9 m^3$)	0.91	1.62
Energy Surplus (GWh)	23	350
Sales Revenue ($ million in 1997 $)	16.7	7.5

Table 7.4: Summary of Base scenario monthly results

Performance Measure	
Percentage of Annual Target Energy	103.1%
Spill Frequency	37%
Failure to meet target generation	49%
Load Factor	66.8%
Payback	7 yrs 4 mths
Discounted Payback	20 yrs 5 mths
Return on Investment	17.27%
Net Present Value (at 10% disc. rate)	$98 million
Benefit-Cost Ratio	1.10
IEA Unit Cost (at 10% DR)	1.52 c/kWh
Internal Rate of Return (real)	11%

Table 7.5: Summary of Base scenario performance indicators

7.3 Climate Impact Analysis

Several analyses are presented in the following sections.

7.3.1 Sensitivity Study

The sensitivity of many aspects of the scheme to changes in climatic variables were assessed by uniformly altering precipitation or temperature levels. No other parameters were altered including other climatic variables. The effect of such changes is explored in the following sections.

Hydrological Sensitivity

As Section 4.3.1 stated runoff is more sensitive to changes in precipitation than temperature and that precipitation change tends to be amplified. Both findings are confirmed in this study as Figure 7.10 shows. Runoff changes are positively related to rainfall, and vice versa for temperature. Runoff demonstrates increased sensitivity to rainfall rise with a 20% increase in rainfall raising annual runoff by 46%, while the opposite change results in a 35% fall.

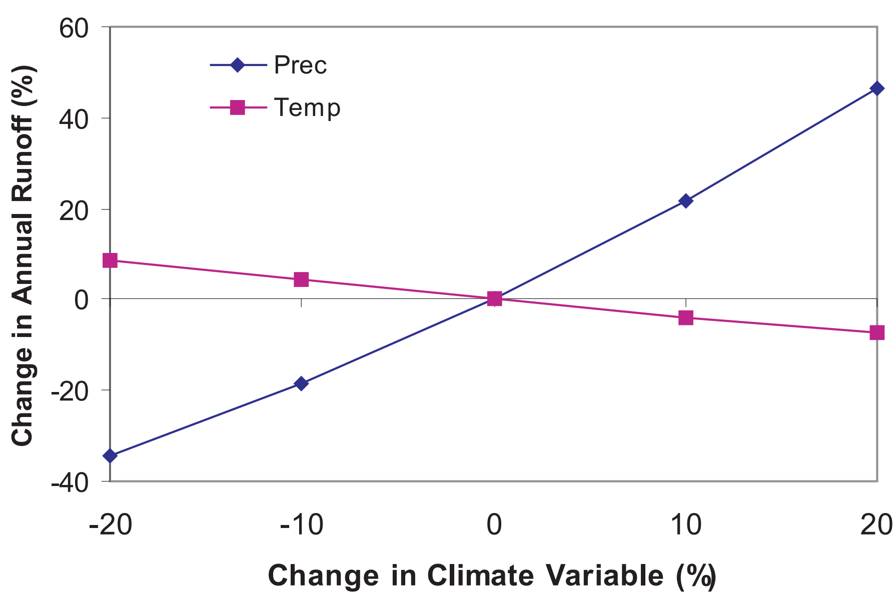


Figure 7.10: Sensitivity of annual runoff to uniform changes in precipitation and temperature (20% temperature change equivalent to 4°C)

Such sensitivity can be expressed in a simple manner using the measure of elasticity, familiar in economics [113]. In this case elasticity (ϕ) is defined as the percentage change in runoff (Q) due to a percentage change in either rainfall (P) or temperature, with $\phi > 1$ indicating sensitivity:

$$\frac{\Delta Q}{Q} = \phi \frac{\Delta P}{P} \tag{7.1}$$

In this instance the elasticity due to rainfall changes is found to be 2.02 (by taking the average of ±10%) which compares well with the value of 1.88 found by Reibsame *et al.* Temperature elasticity is much lower (and negative) at -0.42, indicating that runoff is quite insensitive to temperature changes. This does not agree with the prior study which found that with an elasticity of -1.68, the Zambezi is almost as sensitive to temperature changes as rainfall changes.

The low elasticity for temperature could be accounted for by the low sensitivity of potential evapotranspiration. The Priestley-Taylor method restricts PET rise to 1.25%/ °C temperature rise, well below the 3-4% cited by Budyko [109] and others, although these were global estimates. The low sensitivity may be due to cloud cover or vapour pressure levels restricting the radiation absorption, although without details of the PET approach by Reibsame *et al* a direct comparison cannot be made. Alternatively, the lack of an explicit storage representation for the Barotse or Chobe swamps means that the significant evaporative capabilities of these features is ignored and therefore the evaporation indicated by the model is insufficient.

Once again the annual figure masks the sharp seasonal changes, with a 20% rise in rainfall translating into an almost 50% increase in wet season runoff, and only a 31% change in dry season flows. This indicates that wet season flows are more sensitive, which is a reflection of the soil moisture levels with drier dry season soil able to absorb more of the rainfall increase. Temperature changes show the opposite pattern as the already dry summer soils become proportionately more dry.

In addition to altering mean flows, the variance is also altered. The coefficient of variation (CV) allows a simple and dimensionless measure of this and indicates that a 20% increase in precipitation raises the CV from 70.6% to 78.8%, whilst a precipitation decrease of the same magnitude lowers the CV to 61.9%.

Energy Production

Energy production is constrained by the capacity of the turbines as well as upper and lower bounds on storage. Accordingly, this limits the ability of the station to take advantage of increased river flows, forcing it to spill a significant portion of the increase. Production is more sensitive to reduced flows and this non-linear behaviour is evident in Figure 7.11 in responding to rainfall changes and to a lesser degree to temperature rise.

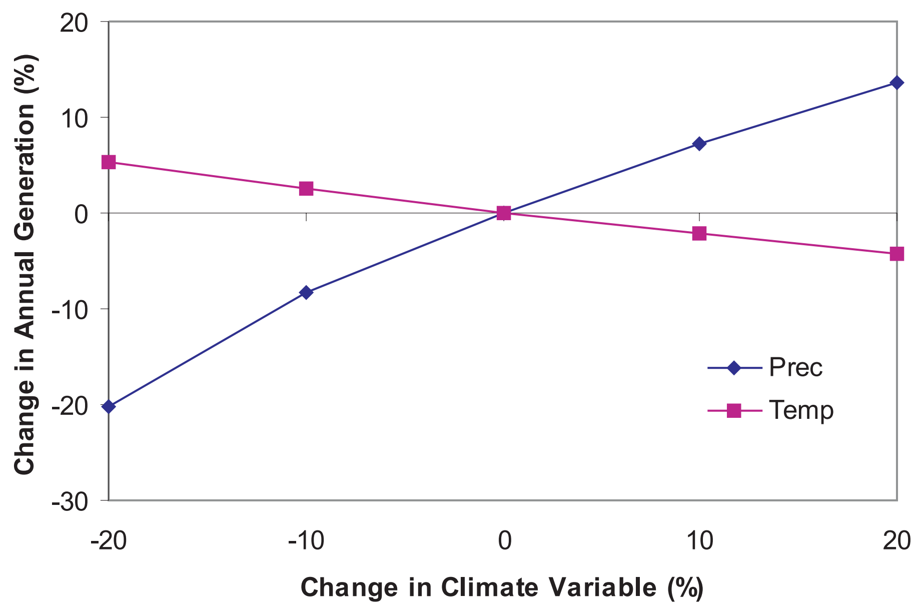


Figure 7.11: Sensitivity of annual generation to changes in precipitation and temperature

Annual production is lowered by over 20% for an equivalent rainfall decrease, which lowers the load factor (to 54%) and increases the frequency of instances where the 757 GWh energy target cannot be met from 49% to 69%. The spillage frequency drops by half and spillage volumes drop to less than one-fifth of the Base value. For a 20% rainfall increase, annual output is increased by nearly 14%, raising the load factor to 77%, spillage frequency to 51% and spill volume by 36%. Temperature changes are less important altering output by just over 1% per degree Celsius change.

Seasonal changes are more marked with the dry season output responding more to climate change with 30.6% and -24.9% changes for 20% rise and fall, respectively, while wet season output alters by 8.5% and -18.7% on the same basis. In addition, dry season production is four times as sensitive to temperature changes as wet season output.

Revenue and Financial Sensitivity

The primary variable in project financial performance is the revenue stream. In this case where a single tariff is in operation, revenue flows follows the pattern of generation and as such have the same sensitivity. Mirroring the changes in revenue, financial performance is positively related to rainfall and a negatively to temperature, although the greater sensitivity is to declining rainfall.

Figure 7.12 shows the variation of key measures with rainfall, with higher rainfall raising net present value and internal rate of return and reducing the discounted payback period. The variations are non-linear, once again reflecting the limitations of the hydro station to take advantage of higher river flows.

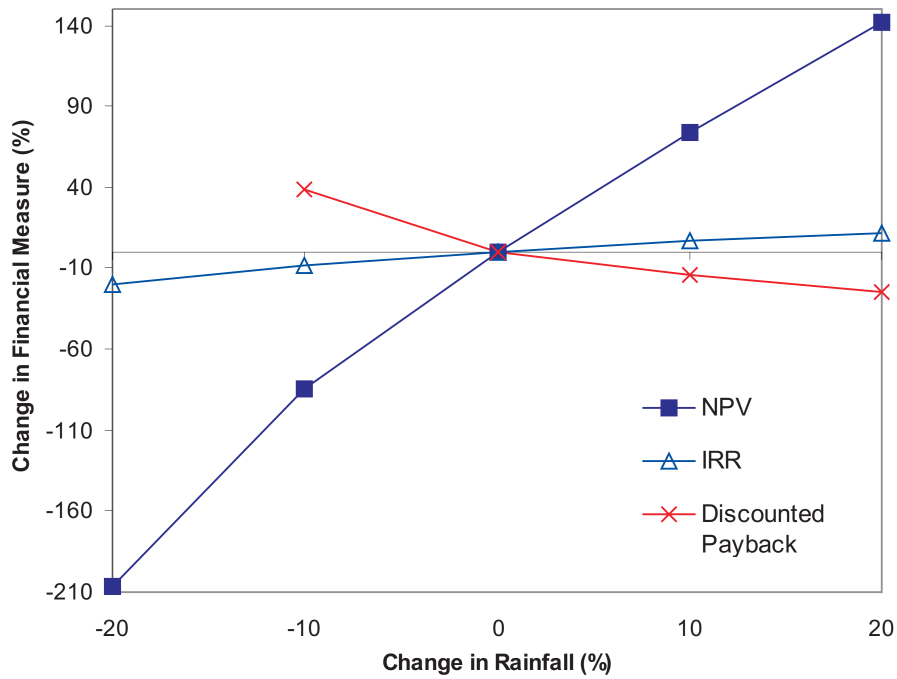


Figure 7.12: Sensitivity of selected financial measures to rainfall changes

Accumulated decreases in annual revenue mean that net present value is very sensitive to changes in rainfall. NPV is reduced by 200% for a rainfall change one-tenth of the size. Internal Rate of Return and discounted payback show smaller but significant variations. For a 20% fall, IRR decreases to 8.8% and the latter increases to over 30 years, beyond the assumed project lifetime (hence the curve in Figure 7.12 is not complete). Other measures also indicate significant changes. For a 20% increase in rainfall, the non-discounted payback period is cut by a year, unit production cost declines by 0.18 c/kWh (12%), while the benefit cost ratio increases to 1.24. Return on investment shows similar sensitivity to IRR. Temperature rise also impacts on financial performance with a +4°C change leading to a 42% fall in NPV, although the impacts on other measures is limited to 4-6%. The effect of changes in both climate variables is summarised in Table A.2 in Appendix A.

The key issue with this sensitivity study is the identification of critical changes that would render the project non-viable. The 20% precipitation decrease results in a negative NPV and consequently an IRR less than 10%. By linear interpolation, the project was found to be able to withstand a uniform 11-12% fall in rainfall and still remain economic (IRR $\geq$ 10%). Therefore, on the basis of the assumptions made, a 11-12% precipitation decrease could be regarded as the critical value for the project. A 20°C temperature rise would be necessary to render the project non-viable.

Climate Sensitivity in Context

While the financial sensitivity appears significant it is useful to compare it with other risks that a project may face, in particular the possibility that project parameters will differ from those estimated at the time of the feasibility study. Large engineering projects including dams are prone to cost and schedule overruns, and sales tariffs may alter in the intervening period between design and operation.

Figure 7.13 shows the sensitivity of net present value to uniform changes in rainfall, temperature and key project assumptions. As civil engineering costs represent a majority of the total, poor estimation may have a significant impact on NPV, as will longer build periods as the loan interest capitalised rises. The project is very sensitive to sales prices with a 20% change representing 0.6 US c/kWh, and it can be seen that rainfall reductions show a similar sensitivity, although the effect of plant capacity reduces the sensitivity to increased rainfall. Once again temperature changes have a relatively minor effect compared to the other changes.

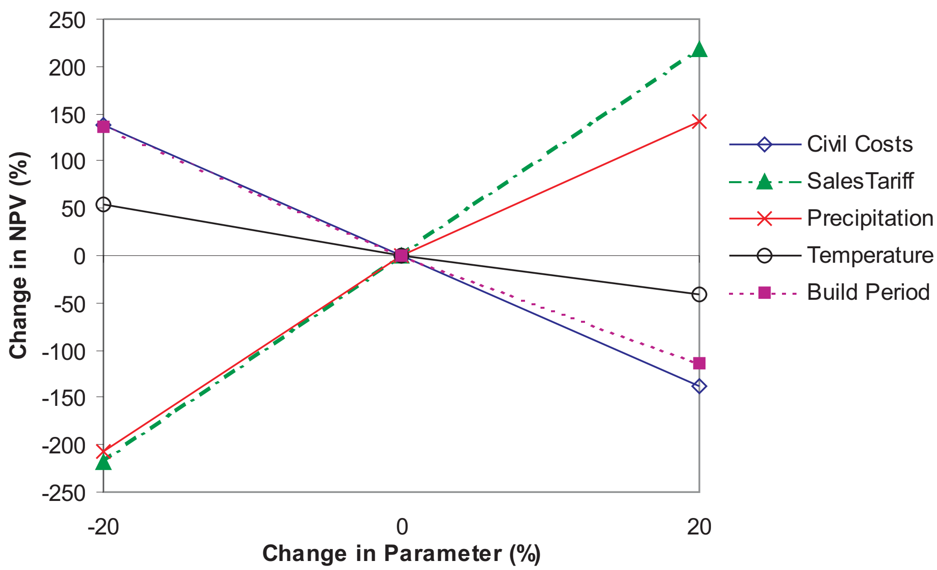


Figure 7.13: Sensitivity of project NPV to climate and project parameter changes (20% temperature change equivalent to 4°C)

Overall Sensitivity

Overall, the system is more sensitive to precipitation change than temperature change. Additionally, rainfall decline is more significant, as constraints on dam storage and generation capacity limit the ability to take advantage of higher riverflows. The variation of sensitivity throughout the climate-finance system is well illustrated by the use of elasticities of precipitation: catchment 2.02, energy production 0.76 and IRR at 0.70. This indicates that while the river basin amplifies changes in rainfall, both the generation and financial components tend to damp changes. The choice of IRR rather than NPV in illustrating elasticity was due to the fact that IRR variations are more representative of the changes in other appraisal measures (NPV showed an elasticity of 7.8).

7.3.2 Scenario Analysis

While sensitivity studies offer an insight to the vulnerability of hydroelectric production and financial performance to changing climate, they cannot be used to determine whether a project should be built. This can to some extent be achieved through the use of climate scenarios that offer a more realistic indication of future rainfall and temperature.

GCM Scenarios

The results from three global circulation models were used:

- HadCM2 model from the Hadley Centre at the UK Meteorological Office,
- ECHAM4 from the German Climate Research Centre, and
- GFDL-R15 from the Geophysical Fluid Dynamics Laboratory.

The models are available through the IPCC DDC and have been included in the AMIP study reported in Second Assessment Report (see Section 2.3.3). Four sets of data were used, the results of transient experiments assuming 1% emissions growth and the HadCM2-S run which incorporated the cooling effects of aerosols. With the exception of the GFDL data, all experiment data is presented in the form of three time slices corresponding to average conditions in the 2020s, 2050s and the 2080s. The former has data relating to the 2020s only.

The climate change anomalies from each period were extracted from the dataset in a similar manner to the observed climate data. The precipitation data was available as absolute changes from the 1961-1990 mean and so this was used to create the required proportional rainfall changes. Each GCM had several grid squares lying within or overlapping the Upper Zambezi basin, and for each one a mask was constructed to spatially average the data. Data is available in monthly averages and these were converted for use in HydroCC, and loaded into the software.

	HadCM2	HadCM2-S	ECHAM4	GFDL-R15
Precipitation in 2020s (%)	92.8	94.8	100.1	103.7
Temperature in 2020s (°C)	+2.0	+1.5	+1.7	+1.7
Precipitation in 2080s (%)	87.5	82.4	98.4	N/A
Temperature in 2080s (°C)	+5.3	+4.4	+5.0	N/A

Table 7.6: Summary of GCM scenarios employed

Two time periods are considered here, the 2020s and the 2080s and the annual changes are given in Table 7.6. The earlier period shows a variation in the magnitude and sign of the annual rainfall totals from each GCM, but all show warming of 1.5-2°C. The three experiments covering the later period indicate that rainfall decreases of 1.4-17.6% accompany warming of 4.4-5.3°C. The inclusion of aerosols is seen to result in a lower mean temperature, but increases rainfall change in the later period.

Conditions in 2020s

Of all the scenarios for the 2020s the HadCM2 is most extreme, both in rainfall decline and temperature rise, and results in a 16.7% fall in annual runoff. The inclusion of aerosols appears to limit change and correspondingly the decrease in annual flows implied by HadCM2-S is restricted to 12.5%. Both ECHAM4 and GFDL-R15 scenarios indicate small annual rainfall increases although the timing of the ECHAM4 rises together with the temperature rises, means that runoff declines by 2.8%. Only the GFDL-R15 scenario results in increased runoff (3.9%).

As most of the additional flow implied by the GFDL scenario occurs during the wet season, only part of the extra can be translated into increased energy, and as such production rises by only 1.2%. For the other scenarios, production decreases along with the changes in flow with mean annual production falling by 8.8%, 1.8% and 6.8% for HadCM2, ECHAM4 and HadCM2-S respectively. As with the sensitivity study, production changes are less severe than changes in runoff.

Once again the financial performance varies directly with production and sales. Figure 7.14 shows the range of NPV resulting from the scenarios, which represent changes of -90% (HadCM2)to +12% (GFDL-R15). The other measures follow a similar pattern, with IRR varying from 10.1% for HadCM2 to 11.1% for GFDL-R15, and discounted payback between 19 years 10 months and 29 years 2 months. Unit production cost is indicated to lie between 1.50 and 1.66 c/kWh. In all instances the investment would be acceptable given the positive NPV, although the small value associated with the HadCM scenario would make it less favourable.

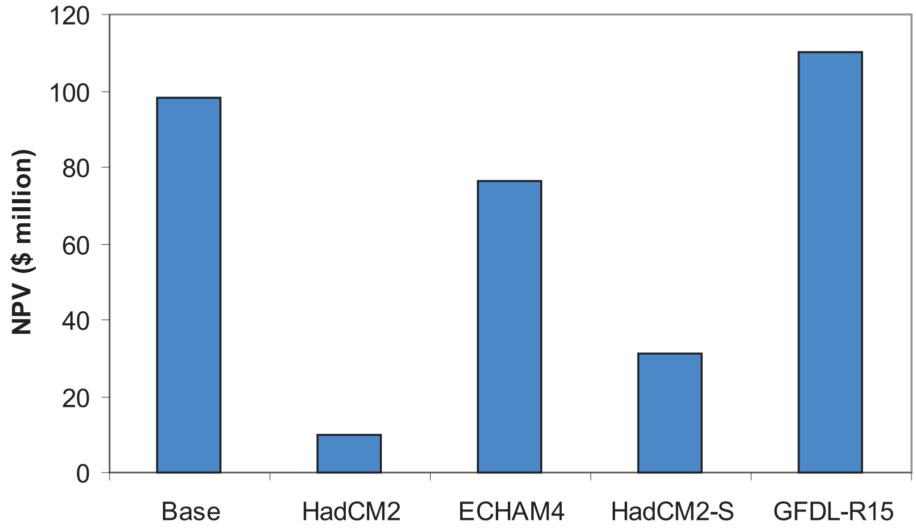


Figure 7.14: Project NPV with four GCM scenarios for the 2020s

Conditions in 2080s

Although the greenhouse gas-only HadCM2 scenario indicates the most severe climatic changes for the 2020s, the aerosol-inclusive HadCM2-S run produces the greatest annual rainfall change in the 2080s (17.6%). ECHAM4 indicates a very slight rainfall decline but warming similar to HadCM2, above that indicated in the aerosol experiment.

Significant variation in monthly rainfall is seen for all three scenarios (Figure 7.15). The HadCM2 scenario shows an 12.1% fall in annual rainfall, although this rises to 15% during the wet season. HadCM2-S shows a similar pattern but with more severe changes particularly in the wet season (19.2% fall). ECHAM4 results in the opposite bias with greater decreases seen during the dry period (-2.6%). Temperature rise is fairly constant throughout the year although HadCM2-S shows slightly greater wet season warming.

The variation in magnitude and timing of rainfall and temperature impacts on the river flow predictions. Figure 7.16 shows that ECHAM4 produces the least change, with a 10% annual decrease, and in line with the rainfall pattern, the fall is greater in the dry season. HadCM2-S indicates the opposite change with flow increases biased slightly towards the wet season within an annual decrease of over one-third.

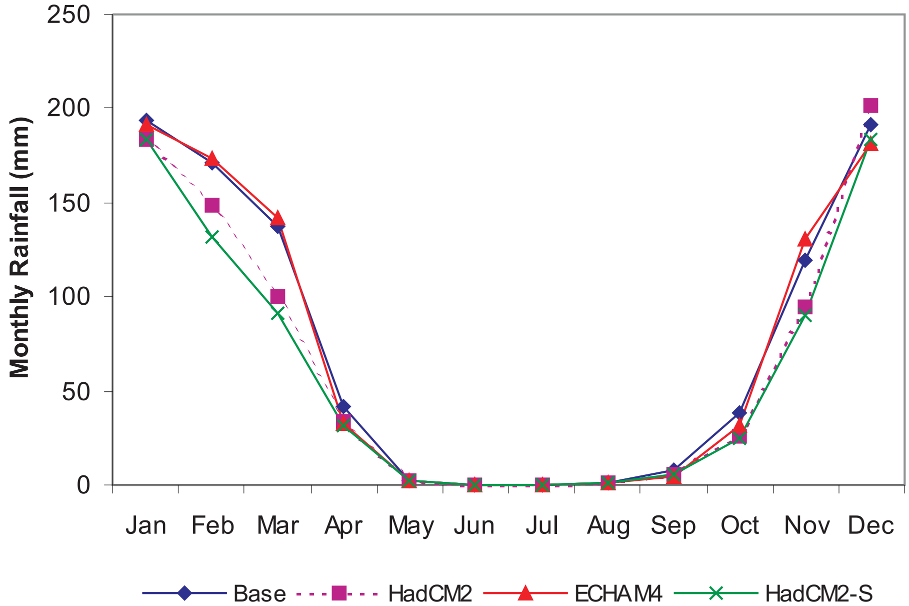


Figure 7.15: Monthly rainfall from three GCM scenarios for the 2080s

The 28.3% fall implied by HadCM2 is spread fairly evenly throughout the year.

In agreement with the results of the sensitivity study, energy production changes less than river flows. Figure 7.17 shows the seasonal changes due to all three scenarios, with energy production viewed as the equivalent power level. The 16.2% annual decrease in energy production from HadCM2 masks a 12.6% fall in wet season output and a 28.3% fall in dry season generation. A 12% decrease in dry season production is the result of the ECHAM4 scenario, while HadCM2-S indicates reductions of, respectively, 21.4%, 18.2% and 32.1% for annual, wet and dry season output.

The decreases in output suggest a serious impact on system firm energy levels. Although peak output falls by 4% at most for the HadCM2-S scenario, mean minimum monthly output drops from 440 MW to 307 MW, more than the installed capacity of the Victoria Falls station.

Real mean monthly sales fall from $16.6 million to $13.1 million for HadCM2-S and $13.9 million for HadCM2. Importantly the variability of the sales stream increases, with the coefficient of variation rising from 44.9% for the base case to 57.2% for HadCM2-S. A greater variability in income could indicate potential for short-term cash flow problems.

Decreases in sales of these magnitudes indicate significant financial impact, and this is indeed the case. Figure 7.18 shows NPV declining by over $60 million for ECHAM4, by $164 million for HadCM2 and by $215 million HadCM2-S scenario.

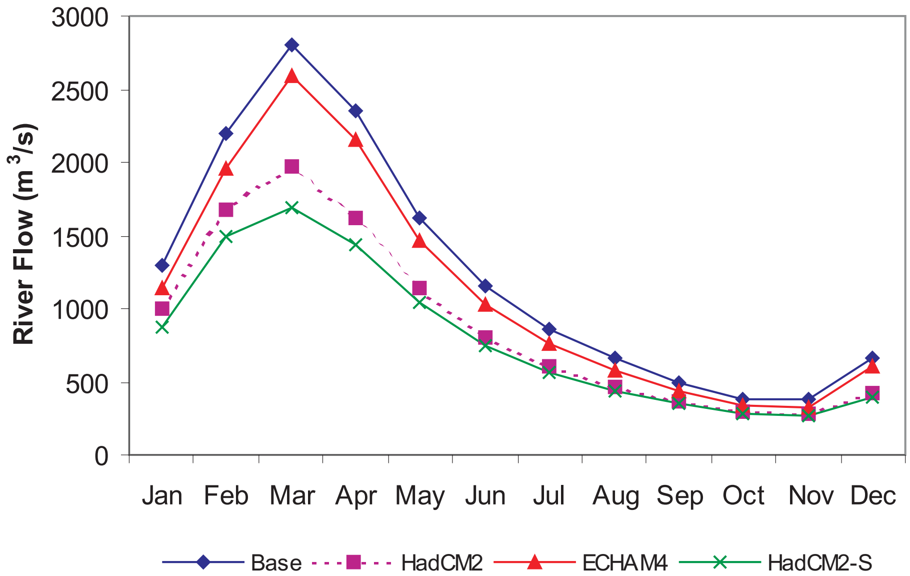


Figure 7.16: Monthly river flows from three GCM scenarios for the 2080s

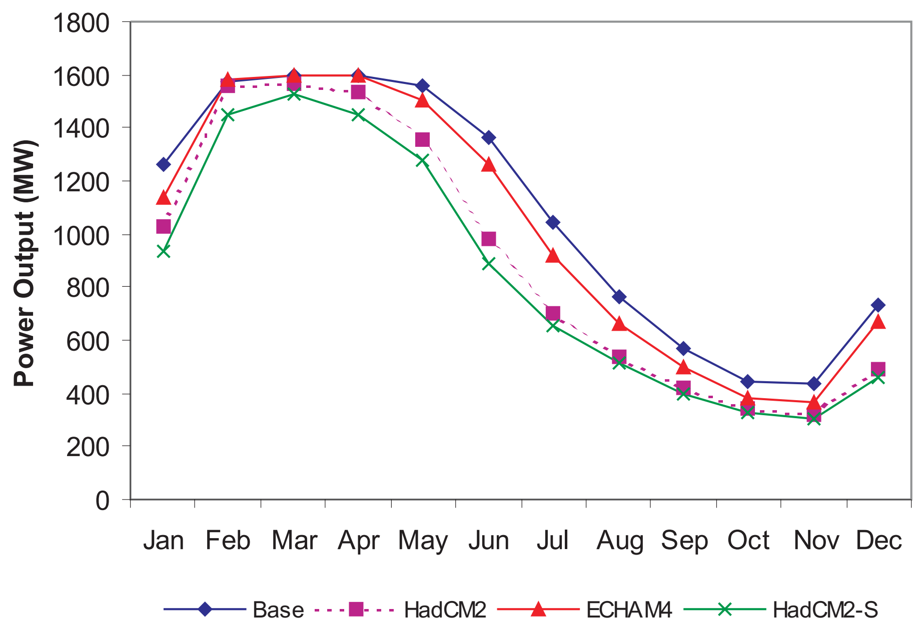


Figure 7.17: Monthly mean power levels from three GCM scenarios for the 2080s

IRR reduces for all three scenarios to 10.35% for ECHAM4, to 8.65 and 9.25% for the aerosol and non-aerosol Hadley scenarios. Discounted payback periods are increased to 25 years 6 months for ECHAM4 and beyond the project lifetime for the Hadley scenarios. Unit production cost also rises to between 1.62 and 1.92 c/kWh (equivalent to 7-26%).

As ECHAM4 results in a positive NPV the project remains financially viable. However, the Hadley scenarios result in significantly negative NPV values, and under either of these circumstances, the project would be considered non-viable.

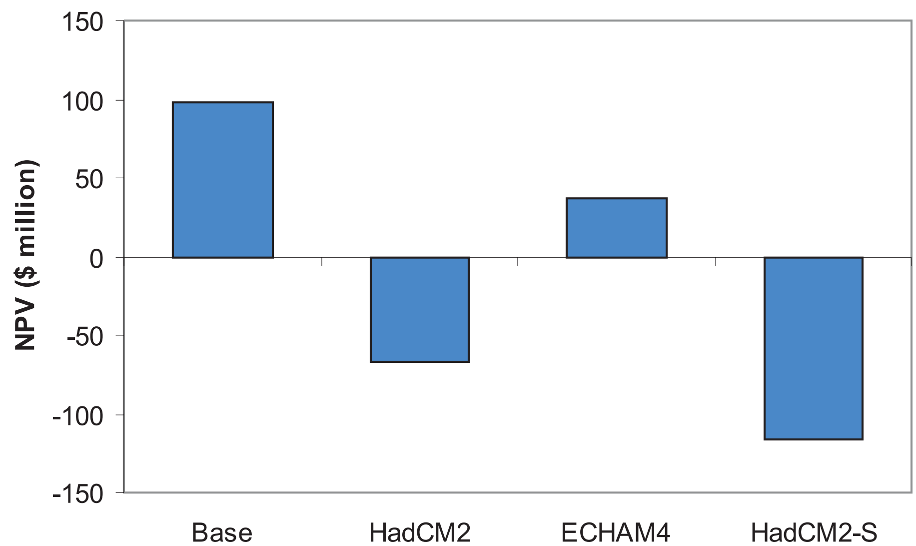


Figure 7.18: Project NPV with four GCM scenarios for the 2080s

Insights from Scenario Analysis

The results of the analyses from the 2020s and 2080s indicate a significant worsening of conditions for investment, as indicated by all measures and in particular NPV. Once again, the sensitivity to increased rainfall is lower than that for decreases, as the results of GFDL-R15 confirms. The wide variation of values indicated by the different scenarios, whilst being useful in defining a range of possible changes, is limited in its application to decision-making. The standard technique for dealing with this is to generate an expected value from a weighted sum of the scenarios. As the probability of individual scenarios becoming reality is uncertain, they must weighted equally. Ignoring the base climate, the scenarios for the 2020s indicate an expected NPV of $56.8 million, representing an expected loss of $40 million compared to the base case, which suggests that on average the project would be viable. For the 2080s the situation deteriorates as the expected NPV becomes -$48.6 million, a loss of \$146.7 million. While such information is useful it does not actually indicate a change in the risk associated with the project, and this can only be examined through a risk analysis.

7.3.3 Risk Analysis

Synthetic series of temperature and precipitation can be constructed from a knowledge of several statistical properties, and HydroCC incorporates a means of analysing and generating such series. The large seasonal variations in rainfall, lead the Markov process to create unstable patterns of synthetic rainfall. As there are, on average, relatively weak correlations between months, an additional routine was added to the HydroCC software to allow random monthly data to be produced based simply on a knowledge of the mean and variance. Several sample series of rainfall were created and the monthly means and standard deviations compared with the observational data. The average monthly mean values varied at most by 15% from the observed, although this was during one of the months with low values. The maximum absolute difference was 7.7 mm/month. Temperature patterns showed similar agreement, and the routine was considered sufficiently accurate for general use.

Therefore, 50 pairs of temperature and precipitation series were created from the observed data, and these were used to drive the model under Base conditions and also with the ECHAM4 scenario for the 2080s. The NPVs and IRRs from each combination of series were extracted and used to create the histogram in Figure 7.19. The mean NPV from the Base period was found to be \$92.5 million, compared to \$98.1 million for the original single run. The mean value from the ECHAM4 series is \$27 million, \$10 million lower than the single series. The standard deviations from both series are similar, at \$18.4 million and \$17.6 million for the Base and GCM scenarios, respectively.

The use of standard deviation to indicate risk in financial markets can be equally applied to capital investments. While the simulations executed here are not true Monte Carlo series, nor are there sufficient series to be truly representative, the effect of changes in climate can be seen. The use of normalised mean values (or coefficient of variation) allows the variances of the Base and ECHAM4 scenarios to be compared. The Base scenario results in a CV of 19.9% compared to 65.1% from ECHAM4, indicating that the risk of the project has increased with climate change.

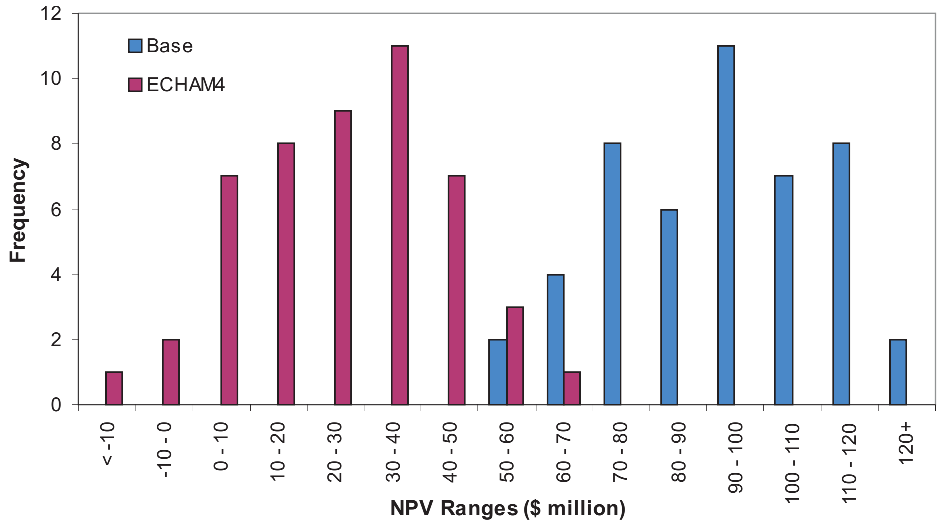


Figure 7.19: Histogram of NPV for Base and GCM scenario for 2080s

7.4 Summary

This chapter begins with a brief description of the Zambezi River basin, the location for the study scheme. The climatological and hydrological characteristics of the basin, the current state of hydroelectric development and key specifications of the Batoka Gorge scheme are all presented. Specific information relating to the acquisition, process and use of various forms of data are detailed and discussed regarding their suitability. A description of the project data, as simulated, precedes analysis of the impact of climatic change using sensitivity, scenario and risk analysis techniques.

Despite their limitations, the three analyses indicate that:

1. the Batoka Gorge scheme is rather sensitive to climate change, particularly rainfall variations,
2. significant financial impacts occur under most GCM scenarios, and in some cases compromise the viability of the scheme, and
3. for the scenario examined, the degree of risk that the scheme faces increases under climate change.

Chapter 8

Discussion and Conclusion

This chapter draws together the issues involved with the future provision of energy and in particular the role of climate. The results from the Batoka Gorge case study are briefly reviewed, before a consideration of the possible implications, both for the study region and globally. A series of possible strategies are presented as means of dealing with climate change in the context of hydropower production and investment. Finally, conclusions are drawn regarding the the salient issues as a whole as well as the specific question of the detrimental impact of climate change on hydropower.

8.1 General Discussion of Results

8.1.1 Sensitivity Analysis

The sensitivity study for the Batoka Gorge scheme confirmed the findings of previous hydrological impact studies by determining that runoff is relatively more sensitive to rainfall than temperature changes, and also that catchments tend to amplify the effects of rainfall changes. Rainfall sensitivity was found to be in agreement with previous studies, although temperature sensitivity is lower due to the poor representation of seasonal hydrology. Energy production from Batoka was found to be less sensitive to climate changes than runoff, indicating that the man-made structure is operating as intended by regulating nature. The financial measures were also found to be less sensitive than runoff, although net present value undergoes very large percentage changes as a result of the compounding effect of changes over the project lifetime. The financial sensitivity to changes in rainfall was similar to variations in energy sales prices, normally identified as a significant project risk. Overall, on the basis of the assumptions, the Batoka Gorge scheme would remain economically viable (real rate of return $> 10\%$) for uniform rainfall changes of less than 12%, or temperature rises of up to 20°C (assuming that the variation is linear).

8.1.2 Scenario Analysis

The scenario analysis indicated that hydropower production and financial return would be less favourable if the scheme was commissioned under conditions expected by the 2020s, and worse still for conditions in the 2080s. The results also demonstrate the compound effect of changes in both rainfall and temperature.

Under conditions indicated by the Hadley model for the 2080s the Batoka Gorge scheme would be uneconomic, assuming that all other factors remain the same. In these circumstances, the financial losses due to climate change (as measured by NPV) range from $60 million to $216 million, which represent up to 19% of the project value (in real terms). The fall in NPV may also be seen as an opportunity cost to society as a whole.

8.1.3 Risk Analysis

Although only one GCM scenario was examined using the limited risk analysis, similar results could be expected for the other scenarios. This is due to the increase in river flow variability resulting from the catchment tendency to amplify rainfall changes. Although hydrological variability does not increase for all scenarios considered, in those which indicated reduced energy production, the variability of energy production does increase (see Tables A.7 and A.8, respectively). It can be inferred that energy production and financial return variability are linked and that under most of the scenarios examined, project returns will be more variable, and hence risk will be greater.

Therefore, it follows that, on the basis of these results, financial risk for hydropower investments will increase, all other things being equal.

8.1.4 Overall Impacts

Overall, the Batoka Gorge scheme is seen to be sensitive to changes in climate, and under most of the scenarios considered experienced significant reductions in financial performance, in some cases the project would be rendered uneconomic (on the basis of the scheme being required to deliver a 10% real return). Coupled to this is an increasing risk of financial performance varying from expected levels. Together these effects would appear to make the Batoka Scheme less attractive as an investment, particularly under the conditions projected for the end of the century.

8.1.5 Reliability of Results

The reliability of the results should be gauged not only on how well the financial measures compare with the Batoka feasibility study (FS) findings, but also on the software's simulation of intermediate processes. To this effect the software performance was examined at several stages during the case study and found that:

- The spatially aggregated observed climate data provided precipitation and PET values in line with previous studies.
- The high degree of correlation between simulated and observed dry season low flows, together with a rainfall elasticity similar to those found in other works, suggest that the hydrological model operates reasonably well, despite poor flood representation.
- The fact that simulated energy production is larger than that reported in the FS follows directly from the less peaky and longer wet season, and the correct performance of the reservoir model is confirmed by the similarity between energy output and inflow values.
- The financial measures indicated by the Base case were similar to those reported in the FS.

Overall, the HydroCC software models the climate-finance process well, providing estimates of annual runoff, generation and financial performance comparable to the Batoka feasibility study. Despite this success, the results of the case study require qualification. Application of the WatBal hydrological model to the Upper Zambezi is limited by its ability to model the complex seasonal hydrology of the upper basin. In particular, the failure to represent the seasonal swamp systems leads to a lower, earlier and longer peak flow season, and lower actual evaporation. As such, it does not deliver a true simulation of seasonal runoff although it is successful in reproducing low flows during the dry season.

Although this failure suggests that the climate changes indicated here cannot be taken as a projection of likely performance, the technique has been validated. The results cannot be relied on as indicating true change, the low sensitivity to temperature (compared to others) resulting from the poor representation of the seasonal swamp systems, could suggest that the basin may in fact be even more sensitive than indicated.

The choice of Batoka Gorge as the study scheme was reasonable, as it was possible to examine it as a stand-alone scheme without influence from upstream flow controls. The complexity of the hydrology created difficulties for accurate modelling and identified some of the limitations of the modelling approach using simplified representations.

8.2 Implications

This section examines the implications for a wide range of issues for the Batoka scheme and for hydropower in general.

8.2.1 Meeting Demand

The reductions in hydropower output suggested by the scenarios are significant, and would imply mean annual energy deficits (relative to the Batoka target output) of up to 824 GWh for the 2020s, and between 580 and 2,000 GWh for the 2080s. These represent losses of 9% and 6-22% respectively. In addition, the results suggested that most scenarios would lead to a fall in in mean minimum monthly production and consequently create problems for system firm energy levels.

The firm power level for the combined Zambian-Zimbabwean system is expected to rise to 2,450 MW with the construction of the Batoka Scheme. Without a system level study it is not possible to determine the effect of climate changes on this figure, although an indication can be gained by using the overall monthly minimum Batoka production level as a proxy. The results indicate that the Base scenario results in a minimum monthly power level of 306 MW, and this is reduced by 16% under the HadCM2 scenario for the 2080s. If this proportional change was repeated on a system level, and ignoring the possible use of Kariba storage to compensate, firm power levels would be reduced to 2,060 MW.

8.2.2 Implied Costs

The shortfall in electricity indicated by the GCM scenarios results in both an opportunity cost, and also the cost of replacement energy, either from existing sources or from new plant. Such costs are not only borne by the investor, but also by society in general. The opportunity cost from lost hydro production is evident in the declining net present values in the results, however the replacement costs require further analysis.

Replacement energy can be sourced from within Zimbabwe (to a limited degree) or from elsewhere via the interconnectors. For example, imports from South Africa at the unit energy cost suggested by the Batoka FS (1.82 US c/kWh), would cover the average annual shortfalls for the 2020s and 2080s, respectively, for $26 million and

$64 million (in real terms).

The alternative is to construct plant to cover the deficit, the capacity of which can be determined from an estimate of the load factor. Assuming approximately the same load factor as Batoka (65%), and ignoring the larger inter-annual range, then the annual average deficit serves as a useful illustration of the implied need. For the GCM scenarios of the 2020s, additional plant of up to 145 MW capacity would be required, although the GFDL-R15 scenario suggests that investment in 20 MW of plant could be foregone at that stage. For the 2080s, the plant requirement increases to between 100 and 350 MW.

An indicative capital cost of $1200/kW for a coal station [225] implies costs of up to $174 million for the 2020s, and $150 to $530 million for the 2080s. These represent sizable capital expenditures over and above the cost of Batoka itself.

8.2.3 Hydropower Investment

The single pseudo-risk analysis indicated that the variability of project returns increased under the ECHAM4 scenario for the 2080s. In addition, all scenarios that resulted in decreased energy production also have increased energy production variability, and therefore greater levels of risk.

The classical view of investment is that greater risk should be compensated by increased returns. However, in the scenarios examined in this study, with the exception of the GFDL-R15 scenario for the 2020s, the return is seen to fall. Therefore the impact is twofold: an increased risk, which according to traditional analysis, should lead to a higher expected return, whilst at the same time a reduction in the expected return possible. Overall, these effects would indicate that investment in hydroelectric power will become less attractive.

It is possible to determine the impact of increase in risk on the expected return but the requirement for an quantitative examination of the overall risk facing the project is beyond the scope of the study. Despite this, the qualitative analysis using only variations in climate is sufficient to show the direction of the change.

Whether the combination of increased risk and lower expected returns would render the project as non-viable depends very much on the project investor or sponsor. Where private investment is involved expected returns below the cost of capital would preclude the project. However, even for the most damaging GCM scenario (HadCM2-S in 2080s), the internal rate of return still manages to reach 8.65% in real terms and 13.65% nominal, which is still a respectable return.

Despite the tendency for greater private capital in the electricity industry, some investments will still be State sponsored or controlled. As such, and particularly when goals other than profit maximisation are involved, lower expected returns resulting from climatic change may still be sufficient to allow a scheme to progress. In the case of Batoka Gorge, the state owned Zimbabwean utility may well accept the risk of lower returns, given the fact that power would still be relatively inexpensive would avoid importation of energy, and would be relatively emission-free.

8.2.4 Regional Emissions

Zimbabwe is well supplied with indigenous coal albeit of a low quality high-sulphur variety, with proven reserves expected to last over 100 years at present usage rates [226]. If the hydro resource of the Zambezi is not harnessed due to the risk of detrimental changes from global warming, then the energy requirements of Zimbabwe will be met by burning more coal.

Hwange, Zimbabwe's main coal-fired power plant emits around one tonne of CO_2 per MWh. To produce the same level of energy as Batoka Gorge, the coal station would emit approximately 9 million tonnes of CO_2, along with 90,000 tonnes of SO_2 and 15,000 tonnes of NO_x [221].

If construction of Batoka were to prevent the expansion of coal burning then, under the Base scenario, 278 million tonnes of CO_2 (75 MtC) emissions would be avoided over the 30 year period. With the avoided emissions varying directly with Batoka output, the GCM scenarios for the 2020s suggest that climate change would necessitate additional coal burning and emissions of the range -3 to 24 Mt CO_2. For the 2080s the additional emissions rise to between 15 and 59 Mt CO_2.

8.2.5 Carbon Abatement and the Clean Development Mechanism

In many respects, and ignoring possible greenhouse emissions during construction, the construction of hydro schemes can be regarded as a carbon abatement option [227]. Abatement costs are simply the ratio of the cost of the measure to the quantity of CO_2 avoided, and may be discounted similar to unit energy costs. A UNEP study considered the options available to Zimbabwe for carbon abatement, including the increased use of hydropower, and estimated that for 2030, average abatement costs would be of the order of \$9/t CO_2 [226].

Once again viewing Batoka as preventing coal burning, the Base case suggests that the \$1.15 billion scheme could be considered to avoid carbon emissions for \$4.09 per tonne of CO_2 (or \$15.13/tC) avoided. At a social discount rate of 5% the abatement cost rises to \$7.60/t CO_2. The selection of discount rate is rather contentious, and delivers widely differing abatement costs (see Arrow *et al* [228]). With either discount rate the abatement cost of constructing Batoka Gorge is lower than the average cost, and significantly below the estimated climate change damage cost of up to \$125/tC [229].

In the same manner as unit energy cost rises under most of the GCM scenarios used in the previous chapter, the same could be said for abatement costs. For the 2020s scenarios, undiscounted abatement costs range from \$4.05 to \$4.48/t CO_2. The more severe 2080s scenarios raise abatement costs by up to 27% (HadCM2-S), ranging from \$4.36 to \$5.21/t CO_2.

Under the Clean Development Mechanism (CDM) of the Kyoto Protocol, a foreign government or business investing in a carbon abatement project in a developing country could claim all or part of the emissions avoided as emissions credits, to offset domestic levels or for use in emissions trading. Whether a foreign entity invests in a particular technology under the CDM depends on the cost per tonne of CO_2 avoided for the project in question and the relative levels of alternatives within the host nation or the marginal abatement cost in the developed nation. With the rise in abatement costs as a result of climate change, Batoka could be become less favourable to would be foreign investors. However, the low cost even with the more extreme GCM scenario would be unlikely to deter a European investor, as their marginal abatement costs tend to be significantly higher [227].

8.2.6 Global Implications

The heterogeneity of hydropower scheme characteristics, hydrological regimes and possible climate changes precludes a detailed global assessment of changes in hydropower potential and investment returns at this stage. However, the IIASA/WEC scenarios provide a useful starting point for examining the impact of reduced energy output or the abandonment of potential hydropower schemes as a result of climate change.

All IIASA/WEC scenarios anticipate that hydropower capacity will increase threefold by the end of the century [74]. As electricity demand must still be satisfied, then any failure to add hydro capacity or maintain production will require alternative generation. The impacts will be illustrated by considering a scenario where hydropower production falls by 10% of expected levels throughout the next century. The reason for the drop could be as a result of actual climate change, or due to potential change that investment in hydropower declines. Given the results for the Batoka Gorge, a 10% fall is not inconceivable.

The IIASA/WEC scenario B (see Figure 3.2) assumes a middle course for growth, and implies that annual energy output from hydropower is expected to increase from 2,420 TWh to 7,420 TWh over the next century. If for either reason production falls by 10% then only 6,920 TWh will be produced in 2100, indicating a cumulative shortfall of 25,000 TWh. Replacing the energy by purchasing energy from existing sources at an average real sales tariff of \$30/MWh (as for Batoka), average annual replacement costs (or opportunity costs) will be in the region of \$12 billion. In terms of replacement plant, a 10% deficit in hydro production could require an additional 130,000 MW of installed capacity (at a 65% load factor) by the end of the century, ignoring retirements. With the same assumptions regarding coal-fired replacement as Section 8.2.2 additional capacity of this magnitude would involve around \$160 billion of investment in real terms over the century.

Making good the shortfall with current coal production technology would release an additional 25 Gt of CO_2 over the century. To put this in context, 25 Gt of CO_2 is approximately the current level of carbon emissions (6.8 GtC), although for this scenario such a quantity would represent just over 3% of total emissions from fossil fuelled electricity generation (with gas stations emitting 45% less CO_2/MWh than coal).

Of course, such calculations are very rough, and it is unlikely that schemes would be abandoned at even intervals over time, rather, the occurrence would become more frequent as climate change progresses. In addition, the changes will be regionally diverse, and it is likely that some regions will fare worse than others.

In all, the potential impact on a global scale could be significant, both in terms of the financial impact of lost production or the the cost of additional generation capacity, and also the subsequent consequence for increased carbon emissions and greater climate change. A detailed study of these aspects is complex and beyond the scope of this work.

8.3 Strategies for Dealing with Climate Change

There are a wide variety of possible areas through which the impact of climate change on hydropower production and investment can be minimised. The following are examples and are by no means an exhaustive list:

8.3.1 Project Location

The Batoka Gorge case study illustrated the effect of climatic change on a project in a fairly arid basin, and in particular the effect of both reduced rainfall and increasing temperature. To reduce the probability of detrimental changes, development would be best advised to concentrate on humid regions and those with forecasts of increasing precipitation.

Figures 8.1 and 8.2 indicate the pattern of temperature and precipitation change by

2080 under the HadCM2-S scenario used in the case study. They show significant warming in the large land masses including southern Africa and the US Mid-West, and significant drying across the Middle East, parts of Latin America and Asia and once again in southern Africa.

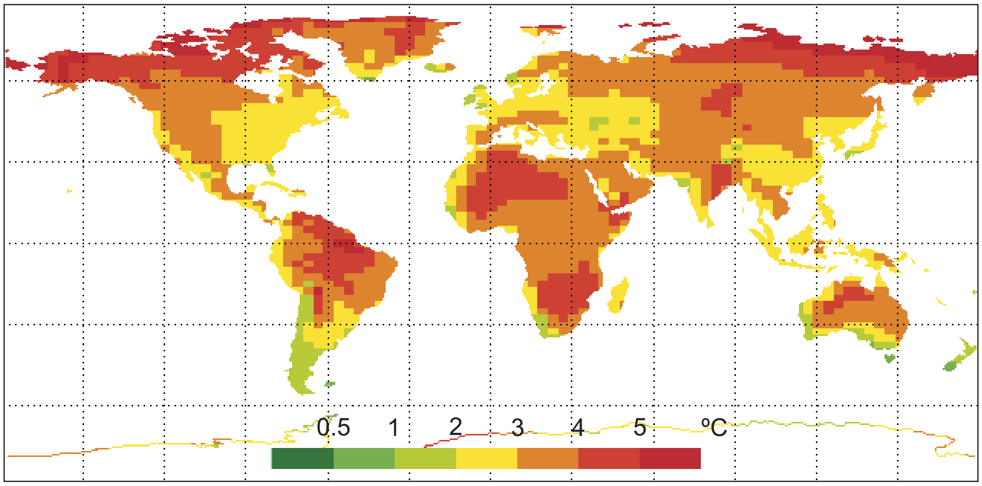


Figure 8.1: HadCM2-S scenario implied temperature changes (°C) for the 2080s relative to 1961-90 mean (from IPCC DDC Data Visualisation Pages)

Hydro development may fare better in the regions with forecast increases in rainfall, although as the case study confirmed, only limited exploitation may be possible, if schemes do not take climate change into account during design. Lower forecast temperatures may be less detrimental, and in mountainous regions increasing temperatures may be beneficial, in the short term at least, as snow and ice patterns change. In addition to regional climate changes, other factors are involved in determining development suitability, ranging from the resource availability to demand and project acceptance. As such, definitive rules on the best location cannot be determined globally and are best examined at a regional level.

8.3.2 Project Size

A series of smaller developments may well create the same level of power but may well be more robust as production may be further optimised. In addition piecewise development is more in tune with the limited financial resources of developing countries and offers flexibility in design and construction, and fewer financial resources at risk at any one time.

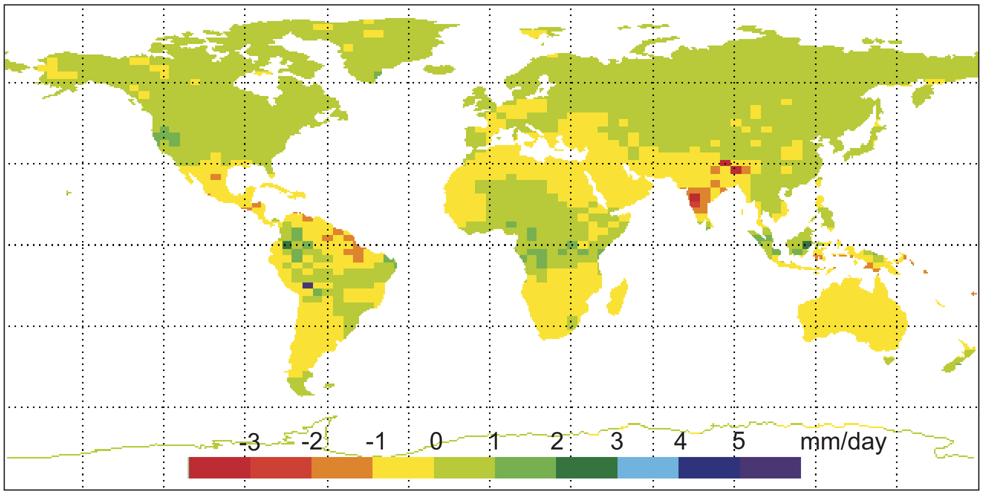


Figure 8.2: HadCM2-S scenario implied precipitation changes (mm/day) for the 2080s relative to 1961-90 mean (from IPCC DDC Data Visualisation Pages)

8.3.3 Project Timing

Given the long lead times involved with hydro schemes the timing of construction and operation are critical. As the results indicate, there appears to be a worsening of conditions up to the 2020s and a further worsening up to 2080, although such a trend may not occur everywhere. Given the need for emissions reductions sooner rather than later, and this apparent deterioration in performance as time passes, the planning, construction and use of hydropower schemes would be best advised to commence as early as possible.

Running counter to this assertion is the relative performance of CCGT plant being constructed in many parts of the world, which will tend to limit hydropower development. However, natural gas is not readily available to all nations and as oil and gas prices will tend to rise over time as resource limits are approached, the competitiveness of gas plant will fall. In addition, the current expectations of investors will have some bearing, particularly the tendency towards short-termism, and high expected returns. Over time these issues could become less severe, primarily as the expected returns to investors are conditioned by market characteristics in the late twentieth century, which may be unsustainable in the longer term.

The scenarios presented here are based on a consistent trend of emissions, which is unlikely to be the case. Additionally, the IPCC reports do not rule out the possibility of 'surprises', for example, the possibility of extremely rapid climate change as a result of positive feedback mechanisms. The possibility of unexpected change further complicates the timing decision.

8.3.4 Technical and Operational Means

Plant capabilities and flexibilities may be increased at the design stage or by retrospectively re-engineering, to take advantage of additional flows or provide increased carry-over storage. Although measures may increase capital cost, the return may be justified and should be determined by cost benefit analysis. For example, a series of measures for the Zambezi were suggested by Reibsame *et al* [114]: increasing turbine efficiency, increasing active storage by installation of lower intakes or the use of back-pumping to optimise water use.

Greater operational flexibility, and the continuous updating of rule curves to adapt to changing hydrological conditions along with increased use of telemetric data will assist in optimising output.

8.3.5 Interconnection

The provision of interconnection between systems will reduce the impact of seasonal shortfalls and improve overall reliability. The creation of regional power power pools may enable more efficient investment, production and consumption patterns to be develop.

8.3.6 Risk Management

Overall, successful investment will be based on the ability of the investor to limit risk. An understanding of potential risks and their consequences is a key task, along with making use of available mechanisms for limiting exposure. For example, project diversification, or the use of joint ventures between companies or Government will allow a sharing of risk. An increased probability of successful investment or lending could be achieved through guaranteed debt repayments either by guarantees from Governments or through the purchase of insurance.

8.3.7 Correcting Market Failure

The inclusion of social costs in pricing enables solutions that are more socially acceptable. As such the crediting of carbon avoidance, emissions trading or a carbon tax would improve the relative disadvantage that hydropower and other renewables face. Such schemes may well assist in limiting the impact of projected climate changes by improving the competitiveness of hydropower.

8.3.8 Assessments

The analysis techniques used in the case study illustrate the magnitude of the climate problem, and the need to take account of it when making investment decisions. The simple approach used here is adequate for project screening, so long as the hydrological model represents reality to a satisfactory degree. In this instance the project has been found to be sensitive to climatic change and given the potential opportunity and additional replacement energy costs identified, along with possibility of greater than simulated sensitivity to temperature, it would be prudent to commission a more detailed study of the impacts.

8.4 Conclusions

Climate change is expected to be the result of increasing atmospheric concentrations of CO_2 and other greenhouse gases, as a result of anthropogenic emissions. Emissions of greenhouse gases have increased greatly since the start of the Industrial Revolution, primarily as a result of the burning of fossil fuels for electricity generation and transportation. In the absence of controls, the continuing economic growth in developing countries suggests that emission levels are set grow significantly over the next century.

The theoretical possibility of global warming as a result of increased levels of CO_2 is supported by data from Antarctic ice cores, from over 400 millenia, and from recent instrumental and paleo-climatic records which indicate a substantial warming of up to 0.6°C since 1850. While such records do not provide absolute proof of Man's influence on the climate system, the evidence is strong and persuasive.

The major method of indicating future climate change is from the use of General Circulation Models, and these complex numerical models indicate temperature rises of around 2°C, although some models indicate significantly larger changes. Accompanying global warming will be changes in regional and global precipitation patterns and other meteorological variables. The effects of these changes will be felt in many areas of human activity, ranging from sea level rise and stress on water resources, to agriculture and human health. Overall, the impact of the changes will have economic impacts which will be borne disproportionately by developing nations.

Given the significant impacts of climate change and the inequity between current levels of emissions and detrimental effects, international agencies have been leading the drive for agreement on reducing emissions. As a first step, the Kyoto Protocol committed industrialised nations to modest cuts in emissions by 2010, although more serious cuts will be required to stabilise concentrations.

As the electricity supply industry is responsible for around a third of all carbon emissions a significant level of emission reductions must occur here. To achieve reductions, reliance on carbon-intensive technologies must be weakened, and low- or no-carbon renewable resources harnessed. Hydropower is the largest single renewable energy source used for electricity generation. It currently meets around a quarter of global electricity requirements, and over the next century hydropower production is forecast to increase threefold.

At the same time as global warming is occurring, the ESI will continue to liberalise, involving increasing levels of private sector involvement in electricity, traditionally the bastion of state-owned utilities. Increased private capital is sought to allow significant levels of investment in new generating capacity as global demand soars. As such the focus for developing generating plant has shifted from the system security and least-cost planning of the old utilities to the profit-maximisation and risk-minimisation approach of the private firm. This implies, and evidence from the UK and elsewhere supports the view that, increasingly, generating capacity with low capital costs and rapid payback periods, considered to be less risky, will be favoured. As such, capital-intensive renewable technologies, such as hydropower, may not be favoured.

Higher evaporation rates arising from warmer temperatures together with altered precipitation patterns may alter the timing and quantity of river flows. Although mean global precipitation is projected to increase by 15%, the increase will be by no means spatially or temporally uniform. Indeed, many areas of the world will see reductions in levels, and consequently falling river flows. As such the energy available for hydropower generation may fall reducing the revenue, and consequently lowering financial returns. With the increased use of private finance, lower expected returns could force the abandonment of potential schemes, and necessitating the construction of fossil-fuelled plant to ensure electricity supplies. As a consequence, not only will a relatively non-polluting source of energy not be used, but additional CO_2 will be emitted which will reduce our ability to deal with the climate change problem effectively.

Previous studies identified the sensitivity of river basins to climate change and some considered the impact on hydropower production. This study follows from the work of Whittington and Gundry and aimed to assess quantitatively the financial impact of changes in precipitation and temperature. The research developed a technique which was subsequently encapsulated in a software tool. Adapted from the standard feasibility study, the reliance on historic river flow patterns is removed by the inclusion of a hydrological model to allow a linkage between climatic variables and financial performance.

The intention was to develop a tool using simple techniques to allow rapid project screening to identify instances where the level of sensitivity warrants deeper investigation. The software tool is based on physically sound models that are well documented and well reviewed. A case study of the proposed Batoka Gorge scheme in the Zambezi River Basin allowed the model to be refined and the technique validated and tested.

The simple hydrological model was found to poorly represent seasonal rivers flows as it did not explicitly account for the effects of the seasonal swamps that make the Zambezi one of the most complex hydrologically. However, as a number of attributes were found to agree closely with observed values and those suggested by the research of others, as well as the limited use of the model to screen projects, the model as a whole was deemed acceptable for use. Three types of analysis were conducted with the model: sensitivity, scenario and risk.

The sensitivity analysis confirmed that river runoff is relatively more sensitive to precipitation change than changes in temperature, and that the catchment tends to amplify proportional changes in precipitation. In terms of financial sensitivity, the scheme was rather sensitive to rainfall reductions although less so to increases, as the turbine and storage capacities limited the ability of the scheme to take advantage of increased flows. Financial performance, as measured by net present value and other measures, was found to fall with decreased precipitation and rising temperature. The sensitivity to rainfall change was found to be comparable to that of variations in electricity sales prices.

The scenario analysis found that for most scenarios financial performance suffered, and conditions were found to worsen over time. Under some scenarios the financial performance deteriorated to such a degree that, on the basis of the expected returns, the project would become non-viable. In the worst case, the net present value of the project, defined by a 10% real discount rate, was found to fall by over $200 million, a significant proportion of the construction cost

Finally, a limited risk analysis was performed using synthetic time series of precipitation and temperature. With risk defined as the standard deviation of the expected net present values, the GCM scenario resulted in increased risk. Inferring that it is the variability of energy production that determines this risk, all scenarios indicating increased production variability are anticipated to indicate increased financial risk.

The results were used to answer three key questions: What impact will climate change have on the financial performance and risk of hydro schemes? How will this affect the terms for financing and the financial returns deemed acceptable by investors? Finally, what will be the consequences for the provision of hydropower worldwide and the ability to meet carbon emission targets?

On the basis of the case study results, climate change reduces the financial performance while simultaneously increasing risk. In addition, a number of implications were identified: difficulties in meeting system demand; opportunity costs resulting from lost production; the cost of replacement energy; a deterioration in the position of the scheme as a means of abating CO_2; and increased CO_2 emissions if fossil fuels were used to make good the shortfall in production.

Although quantitative answers to the second and third questions are beyond the scope of this thesis, qualitative treatments identified the likely impacts. Firstly, the increased risk would tend to increase the expected return and make the financing terms less favourable. An increasing possibility that schemes could be abandoned on the basis of a deteriorating financial return and increased risk, along with the changes in the production from operating schemes, would appear to indicate a shortfall in overall generating capacity relative to expectations. A simple example indicated that the impact of such changes in terms of the requirement for additional non-hydropower generating capacity and the consequent increase in CO_2 emissions could be significant.

Together the three questions indicate that the hypothesis can be affirmed: does climate change adversely affect production from hydropower schemes and consequently deter investment in them? The answer on the basis of the research and the results from the case study, is yes.

8.5 Recommendations for Further Work

8.5.1 Full Monte Carlo Analysis

As the scenario analysis showed, the compound effects of more than one change can have a significantly greater impact than the individual changes. As such, simply altering the rainfall and temperature by amounts determined by a single GCM scenario will not provide the true range of outcomes. To overcome this limitation, multiple GCM scenarios could be used together with random values for other key project parameters. With GCM scenarios selected at random, a more comprehensive analysis would allow single values for both risk and expected returns to be made. This would establish that, for climate change scenarios as a whole, financial risk would be seen to increase and return would fall.

8.5.2 Scenario Type

The GCM scenarios used in the case study are all averaged from sections of a transient experiment, and whilst not as unrealistic as equilibrium scenarios still impose a mean change with no alteration of the temporal pattern. In reality, changes to conditions are likely to occur over time, and so the full climate change will not be seen in the early years. Use of time series values from transient experiments would allow these effects to be examined, although the direct use of GCM output would not be sensible at this stage.

8.5.3 Global Analysis

A more detailed analysis of global impacts similar to that presented in Section 8.2.6 would be a very useful extension of the work. Long term plant investment models would be necessary to indicate the hydropower investment levels, by taking into account the relative costs and risks of numerous generating methods. Changes in hydropower production would have to be driven by prevailing climate conditions, and some direct linkage between past performance and future investment levels would have to be incorporated. A regional assessment is likely to be the most sensible approach, although this may not allow investigation of the significant differences between projects.

8.6 Thesis Conclusion

The thesis draws together information and techniques from a disparate number of subject areas, and uses them to identify gaps in the body of knowledge surrounding the climate change issue. The thesis describes a first attempt to quantitatively assess the effect of changing climate on the financial performance of hydropower schemes. The works forms the basis for further investigations into the impact of changing levels of hydropower investment on global CO_2 levels.

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Appendix A

Case Study Details

A.1 Detailed Project Costs

Table A.1 provides the breakdown for the major cost items for the Batoka scheme.

	Item	US$ million
A	Civil Works	
A1	Direct costs	470,266
A2	Indirect costs (19% of A1)	89,351
A3	Contingencies (20% of A1 + A2)	111,923
A4	Total Civil Works	671,540
B	Mechanical Equipment/Hydraulic Steel Structure	
B1	Direct and indirect costs	200,300
B2	Contingencies (10% of B1)	20,036
B3	Total	220,396
C	Electrical	
C1	Direct/indirect	155,482
C2	Contingencies (10% of C1)	15,548
C3	Total	171,030
	Total Construction Cost	1,062,966
	Engineering, administration and supervision	85,037
	Client's own cost	5,315
	Basic Cost	1,153,318

Table A.1: Detailed costs for Batoka Dam [221]

A.2 Water Balance Model Calibration

Figure A.1 shows the relative sensitivity of annual runoff to 10% variations in the optimal WatBal parameters given in Section 7.2.2. Figure A.2 shows the optimal match between observed and simulated river flows over the period 1961 to 1990.

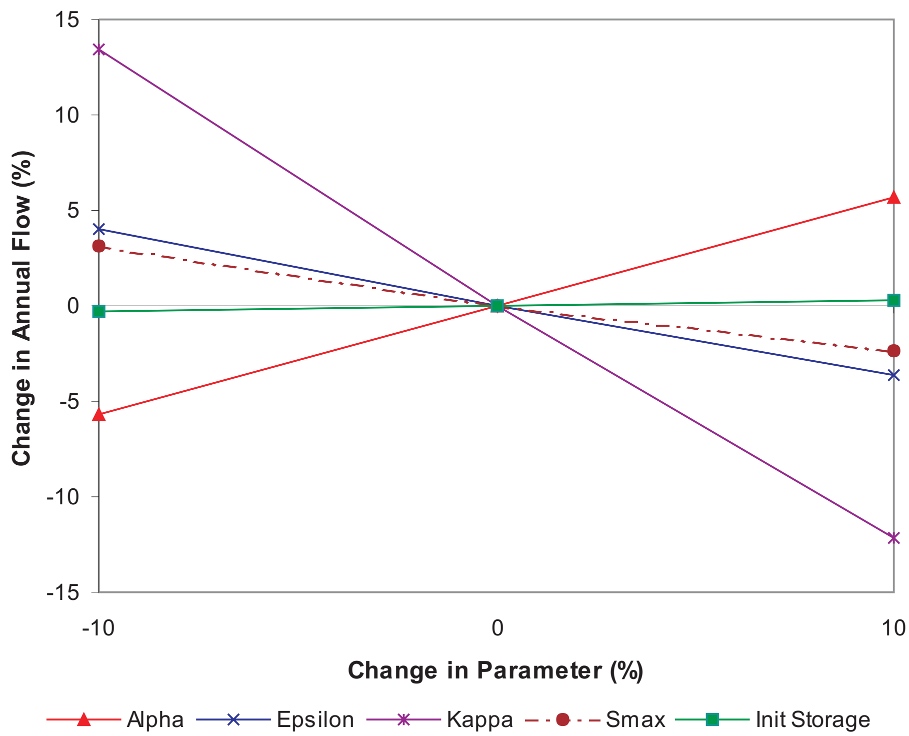

Figure A.1: Annual flow sensitivity to WatBal parameter values

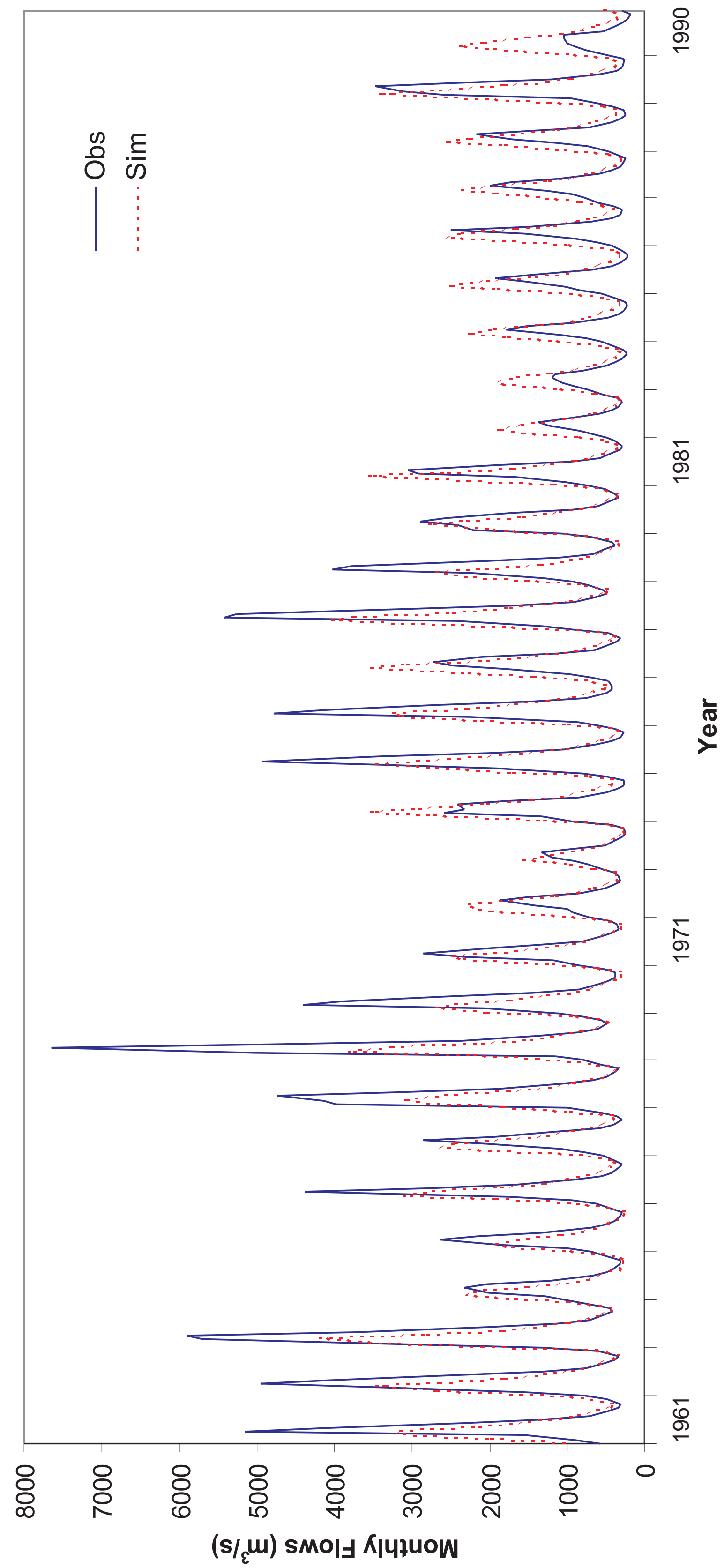

Figure A.2: Comparison of observed and simulated flows

A.3 Climate Impact Studies

Table A.2 indicates the changes in the financial performance measures with changes of ± 20% precipitation and 4°C temperature rise

Financial Measure	Precipitation		Temperature
	+20%	-20%	+4°C
NPV	142	-207	-42
IRR	12	-20	-4
Benefit Cost Ratio	13	-19	-4
Payback	-14	30	6
Discounted Payback (10%)	-24	¿50	15
Return on Investment	16	-24	-5
Unit Cost (10%)	-12	25	4

Table A.2: Summary of financial measure sensitivity (percentage change)

Tables A.3 and A.4 show the monthly mean, standard deviation and coefficient of variation of river flows and energy production, respectively, for uniform changes in precipitation and temperature.

Tables A.5 to A.8 shows the monthly mean, standard deviation and coefficient of variation for each of the GCM scenarios, for precipitation, temperature, river flow and energy production, respectively.

Table A.9 presents the full range of financial impacts for each GCM scenario.

Scenario	Measure	Month												Annual
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Base	μ (BCM)	3.47	5.33	7.52	6.09	4.33	2.98	2.32	1.76	1.28	1.04	0.99	1.76	3.21
	σ (BCM)	0.94	1.13	1.87	1.65	1.09	0.76	0.57	0.41	0.27	0.19	0.21	0.54	2.27
	CV (%)	27.16	21.29	24.83	27.16	25.25	25.39	24.63	23.29	20.85	18.32	21.43	30.60	70.74
Precipitation +20%	μ (BCM)	5.41	8.71	12.08	8.87	5.86	3.98	3.05	2.28	1.63	1.29	1.25	2.53	4.71
	σ (BCM)	1.67	2.07	3.28	2.57	1.46	1.00	0.75	0.54	0.36	0.26	0.32	0.89	3.71
	CV (%)	30.84	23.80	27.13	28.96	24.87	25.03	24.67	23.83	22.07	20.52	25.23	35.03	78.85
Precipitation +10%	μ (BCM)	4.35	6.85	9.61	7.41	5.08	3.47	2.67	2.02	1.45	1.16	1.11	2.12	3.91
	σ (BCM)	1.27	1.55	2.51	2.08	1.28	0.88	0.66	0.48	0.31	0.23	0.26	0.70	2.93
	CV (%)	29.10	22.61	26.09	28.05	25.10	25.29	24.74	23.71	21.61	19.55	23.47	32.89	74.84
Precipitation -10%	μ (BCM)	2.76	4.10	5.81	4.93	3.63	2.52	1.97	1.52	1.13	0.92	0.87	1.47	2.61
	σ (BCM)	0.69	0.82	1.37	1.30	0.92	0.63	0.48	0.34	0.22	0.16	0.17	0.41	1.74
	CV (%)	25.20	19.95	23.53	26.28	25.27	25.23	24.24	22.67	19.85	16.87	19.28	28.01	66.50
Precipitation -20%	μ (BCM)	2.18	3.12	4.42	3.91	2.97	2.09	1.66	1.30	0.98	0.82	0.77	1.22	2.10
	σ (BCM)	0.51	0.59	0.99	1.00	0.75	0.52	0.39	0.28	0.18	0.13	0.13	0.31	1.30
	CV (%)	23.59	18.95	22.33	25.54	25.11	24.89	23.53	21.61	18.52	15.23	16.86	25.13	62.05
Temperature +2°C	μ (BCM)	3.34	5.14	7.27	5.90	4.19	2.86	2.21	1.68	1.22	0.99	0.94	1.69	3.10
	σ (BCM)	0.90	1.09	1.80	1.61	1.07	0.73	0.55	0.39	0.25	0.18	0.20	0.51	2.20
	CV (%)	27.00	21.20	24.81	27.35	25.50	25.58	24.68	23.25	20.64	17.86	20.92	30.37	71.21
Temperature +4°C	μ (BCM)	3.23	4.98	7.05	5.74	4.06	2.76	2.12	1.60	1.17	0.95	0.91	1.62	2.99
	σ (BCM)	0.87	1.05	1.75	1.58	1.04	0.71	0.53	0.37	0.24	0.17	0.19	0.49	2.14
	CV (%)	26.85	21.10	24.88	27.46	25.69	25.77	24.75	23.26	20.37	17.51	20.44	30.24	71.63
Temperature −2°C	μ (BCM)	3.62	5.54	7.81	6.31	4.50	3.12	2.43	1.86	1.36	1.10	1.04	1.85	3.35
	σ (BCM)	0.99	1.19	1.94	1.71	1.12	0.78	0.60	0.43	0.29	0.21	0.23	0.57	2.35
	CV (%)	27.33	21.40	24.77	27.02	24.92	25.09	24.53	23.31	21.06	18.79	21.92	30.80	70.16

Table A.3: Monthly river flows for uniform changes in climate

Scenario	Measure	Month												Annual
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Base	μ (GWh)	938.38	1060.07	1190.40	1152.00	1159.04	979.73	777.50	569.66	411.10	331.84	316.46	542.34	780.34
	σ (GWh)	210.64	81.47	0.00	0.00	90.46	215.34	219.48	142.20	86.01	61.24	67.99	138.67	350.29
	CV (%)	22.45	7.69	0.00	0.00	7.80	21.98	28.23	24.96	20.92	18.45	21.48	25.57	44.89
Precipitation +20%	μ (GWh)	1147.74	1075.20	1190.40	1152.00	1190.40	1116.35	1009.74	767.64	525.42	412.42	402.14	734.80	887.32
	σ (GWh)	118.34	0.00	0.00	0.00	0.00	100.31	234.24	215.99	123.52	84.89	101.45	242.25	326.18
	CV (%)	10.31	0.00	0.00	0.00	0.00	8.99	23.20	28.14	23.51	20.58	25.23	32.97	36.76
Precipitation +10%	μ (GWh)	1077.63	1066.62	1190.40	1152.00	1183.35	1045.26	919.00	656.67	465.13	371.03	357.24	616.11	836.16
	σ (GWh)	162.46	46.21	0.00	0.00	35.97	162.25	254.05	173.02	100.73	72.87	83.82	163.99	339.48
	CV (%)	15.08	4.33	0.00	0.00	3.04	15.52	27.64	26.35	21.66	19.64	23.46	26.62	40.60
Precipitation -10%	μ (GWh)	793.15	1055.00	1180.09	1135.76	1094.34	851.44	643.54	487.11	360.27	295.50	280.00	470.47	715.24
	σ (GWh)	188.57	96.28	52.46	74.00	158.80	240.86	172.72	110.53	71.69	50.28	54.01	131.98	354.13
	CV (%)	23.77	9.13	4.45	6.52	14.51	28.29	26.84	22.69	19.90	17.02	19.29	28.05	49.51
Precipitation -20%	μ (GWh)	651.46	863.38	1114.84	1052.58	982.02	709.83	529.82	415.69	313.58	262.53	247.95	390.69	623.35
	σ (GWh)	115.98	166.01	144.35	178.23	246.80	223.32	124.15	90.26	58.23	40.25	41.89	98.42	334.70
	CV (%)	17.80	19.23	12.95	16.93	25.13	31.46	23.43	21.71	18.57	15.33	16.89	25.19	53.69
Temperature +2°C	μ (GWh)	915.64	1063.73	1190.00	1150.00	1154.66	951.77	743.49	540.55	390.69	315.94	302.13	518.04	764.36
	σ (GWh)	211.29	87.63	0.00	0.00	101.34	231.62	217.99	132.02	80.85	56.95	63.45	130.37	355.95
	CV (%)	23.08	8.24	0.00	0.00	8.78	24.34	29.32	24.42	20.69	18.02	21.00	25.17	46.57
Temperature +4°C	μ (GWh)	883.52	1063.45	1190.40	1152.00	1138.00	932.08	711.25	513.14	373.41	302.64	290.21	505.52	749.36
	σ (GWh)	209.20	63.26	0.00	0.00	116.35	240.42	217.30	118.50	76.36	53.27	59.60	133.86	359.44
	CV (%)	23.68	5.95	0.00	0.00	10.22	25.79	30.55	23.09	20.45	17.60	20.54	26.48	47.97
Temperature −2°C	μ (GWh)	975.33	1061.22	1190.40	1152.00	1169.86	1002.00	833.99	595.66	435.21	350.88	333.72	563.36	799.77
	σ (GWh)	206.81	75.28	0.00	0.00	73.09	202.77	244.56	145.59	91.91	66.25	73.35	141.79	346.26
	CV (%)	21.20	7.09	0.00	0.00	6.25	20.24	29.32	24.44	21.12	18.88	21.98	25.17	43.29

Table A.4: Monthly energy production for uniform changes in climate

Scenario	Years	Measure	Month												Annual
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Base	61-90	μ (mm/mth)	193.61	171.64	136.83	41.34	2.48	0.25	0.00	0.81	7.43	38.78	119.69	191.11	74.64
		σ (mm/mth)	25.74	30.59	40.77	22.17	3.63	0.51	0.00	1.20	3.24	15.20	33.56	30.79	78.93
		CV (%)	13.30	17.82	29.80	53.63	146.52	204.32		148.10	43.66	39.21	28.04	16.11	105.75
HadCM2	2020s	μ (mm/mth)	185.01	159.81	115.85	33.76	3.01	0.39	0.00	0.76	6.58	33.33	107.90	192.57	69.20
		σ (mm/mth)	24.60	28.48	34.52	18.11	4.41	0.79	0.00	1.12	2.87	13.07	30.26	31.03	75.11
		CV (%)	13.30	17.82	29.80	53.63	146.52	204.32		148.10	43.66	39.21	28.04	16.11	108.54
HadCM2-S	2020s	μ (mm/mth)	204.25	154.15	116.88	37.40	2.01	0.29	0.00	0.78	6.62	33.30	112.81	188.49	70.71
		σ (mm/mth)	27.16	27.47	34.83	20.06	2.95	0.60	0.00	1.15	2.89	13.06	31.64	30.37	77.00
		CV (%)	13.30	17.82	29.80	53.63	146.53	204.32		148.10	43.66	39.21	28.04	16.11	108.89
ECHAM4	2020s	μ (mm/mth)	196.02	174.01	142.41	35.89	2.07	0.06	0.00	1.46	5.72	46.06	115.87	185.42	74.80
		σ (mm/mth)	26.07	31.01	42.43	19.24	3.04	0.11	0.00	2.17	2.50	18.06	32.49	29.88	79.22
		CV (%)	13.30	17.82	29.80	53.63	146.53	204.32		148.10	43.66	39.21	28.04	16.11	105.90
GFDL-R15	2020s	μ (mm/mth)	188.76	170.63	158.11	37.09	3.63	0.24	0.00	0.62	7.94	28.76	139.77	201.71	77.21
		σ (mm/mth)	25.10	30.41	47.11	19.89	5.32	0.49	0.00	0.92	3.47	11.28	39.19	32.50	82.82
		CV (%)	13.30	17.82	29.80	53.63	146.52	204.32		148.10	43.66	39.21	28.04	16.11	107.26
HadCM2	2080s	μ (mm/mth)	183.97	148.73	100.30	28.23	2.59	0.43	0.00	1.52	6.01	26.25	94.68	201.39	65.42
		σ (mm/mth)	24.46	26.51	29.89	15.14	3.79	0.88	0.00	2.24	2.62	10.29	26.55	32.45	74.12
		CV (%)	13.30	17.82	29.80	53.63	146.52	204.32		148.10	43.66	39.21	28.04	16.11	113.30
HadCM2-S	2080s	μ (mm/mth)	183.66	131.30	91.66	31.66	2.36	0.27	0.00	1.01	5.53	24.29	90.26	183.14	61.41
		σ (mm/mth)	24.42	23.40	27.31	16.98	3.46	0.55	0.00	1.50	2.41	9.52	25.31	29.51	69.39
		CV (%)	13.30	17.82	29.80	53.63	146.52	204.32		148.10	43.66	39.21	28.04	16.11	113.00
ECHAM4	2080s	μ (mm/mth)	191.01	173.59	142.01	33.03	2.44	0.46	0.00	0.93	4.29	31.10	131.18	181.09	73.48
		σ (mm/mth)	25.40	30.94	42.32	17.71	3.57	0.95	0.00	1.38	1.87	12.19	36.79	29.18	79.47
		CV (%)	13.30	17.82	29.80	53.63	146.52	204.32		148.10	43.66	39.21	28.04	16.11	108.15

Table A.5: Monthly precipitation variation for all GCM scenarios

Scenario	Years	Measure	Month												Annual
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Base	61-90	μ (°)C	23.63	23.58	23.55	22.41	19.78	17.20	16.89	19.63	23.22	24.94	24.05	23.43	21.94
		σ (°)C	0.60	0.52	0.59	0.48	0.99	0.83	0.75	0.87	0.45	0.59	0.64	0.50	2.72
		CV (%)	2.52	2.21	2.49	2.13	5.01	4.84	4.44	4.43	1.95	2.36	2.65	2.12	12.41
HadCM2	2020s	μ (°)C	25.20	25.22	25.45	25.17	22.33	19.39	18.97	21.68	24.41	27.40	26.25	25.14	23.97
		σ (°)C	0.60	0.52	0.59	0.48	0.99	0.83	0.75	0.87	0.45	0.59	0.64	0.50	2.65
		CV (%)	2.36	2.06	2.30	1.89	4.44	4.30	3.95	4.01	1.85	2.15	2.43	1.98	11.07
HadCM2-S	2020s	μ (°)C	23.63	23.58	23.55	22.41	19.78	17.20	16.89	19.63	23.22	24.94	24.05	23.43	23.48
		σ (°)C	0.60	0.52	0.59	0.48	0.99	0.83	0.75	0.87	0.45	0.59	0.64	0.50	2.75
		CV (%)	2.52	2.21	2.49	2.13	5.01	4.84	4.44	4.43	1.95	2.36	2.65	2.12	11.71
ECHAM4	2020s	μ (°)C	25.31	24.90	24.79	23.73	21.48	19.32	19.46	21.58	25.01	26.40	25.54	25.12	23.64
		σ (°)C	0.60	0.52	0.59	0.48	0.99	0.83	0.75	0.87	0.45	0.59	0.64	0.50	2.44
		CV (%)	2.35	2.09	2.37	2.01	4.62	4.31	3.85	4.03	1.81	2.23	2.49	1.98	10.33
GFDL-R15	2020s	μ (°)C	25.34	25.54	24.92	23.71	21.37	18.85	18.65	21.06	25.06	27.47	25.84	24.98	23.65
		σ (°)C	0.60	0.52	0.59	0.48	0.99	0.83	0.75	0.87	0.45	0.59	0.64	0.50	2.83
		CV (%)	2.35	2.04	2.35	2.01	4.64	4.42	4.02	4.13	1.81	2.14	2.47	1.99	11.99
HadCM2	2080s	μ (°)C	27.70	28.03	28.64	28.91	25.86	23.06	23.14	25.05	26.38	31.33	30.27	27.87	27.27
		σ (°)C	0.60	0.52	0.59	0.48	0.99	0.83	0.75	0.87	0.45	0.59	0.64	0.50	2.57
		CV (%)	2.15	1.86	2.05	1.65	3.84	3.61	3.24	3.47	1.72	1.88	2.10	1.79	9.43
HadCM2-S	2080s	μ (°)C	26.94	27.38	28.15	27.99	24.47	21.32	21.73	23.74	26.12	30.36	29.43	27.36	26.33
		σ (°)C	0.60	0.52	0.59	0.48	0.99	0.83	0.75	0.87	0.45	0.59	0.64	0.50	2.84
		CV (%)	2.21	1.90	2.08	1.70	4.05	3.91	3.45	3.66	1.73	1.94	2.16	1.82	10.77
ECHAM4	2080s	μ (°)C	27.94	27.46	27.31	26.74	24.82	22.90	22.82	24.83	28.57	31.77	29.00	28.34	26.96
		σ (°)C	0.60	0.52	0.59	0.48	0.99	0.83	0.75	0.87	0.45	0.59	0.64	0.50	2.61
		CV (%)	2.13	1.90	2.15	1.78	4.00	3.64	3.28	3.50	1.58	1.85	2.20	1.76	9.67

Table A.6: Monthly temperature variation for all GCM scenarios

Scenario	Years	Measure	Month												Annual
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Base	61-90	μ (BCM)	3.47	5.33	7.52	6.09	4.33	2.98	2.32	1.76	1.28	1.04	0.99	1.76	3.21
		σ (BCM)	0.94	1.13	1.87	1.65	1.09	0.76	0.57	0.41	0.27	0.19	0.21	0.54	2.27
		CV (%)	27.16	21.29	24.83	27.16	25.25	25.39	24.63	23.29	20.85	18.32	21.43	30.60	70.74
HadCM2	2020s	μ (BCM)	3.00	4.54	6.17	4.96	3.59	2.47	1.93	1.48	1.09	0.90	0.84	1.43	2.68
		σ (BCM)	0.78	0.94	1.45	1.26	0.89	0.61	0.46	0.33	0.21	0.15	0.15	0.40	1.86
		CV (%)	26.06	20.70	23.56	25.46	24.71	24.77	23.72	22.04	19.15	16.22	18.17	27.90	69.27
HadCM2-S	2020s	μ (BCM)	3.47	5.33	7.52	6.09	4.33	2.98	2.32	1.76	1.28	1.04	0.99	1.76	2.81
		σ (BCM)	0.94	1.13	1.87	1.65	1.09	0.76	0.57	0.41	0.27	0.19	0.21	0.54	1.96
		CV (%)	27.16	21.29	24.83	27.16	25.25	25.39	24.63	23.29	20.85	18.32	21.43	30.60	69.85
ECHAM4	2020s	μ (BCM)	3.29	5.17	7.46	5.98	4.22	2.88	2.22	1.68	1.23	0.99	0.98	1.70	3.13
		σ (BCM)	0.88	1.08	1.86	1.60	1.05	0.72	0.54	0.38	0.25	0.17	0.22	0.52	2.24
		CV (%)	26.86	20.89	24.87	26.73	24.95	25.06	24.23	22.84	20.27	17.54	22.18	30.64	71.68
GFDL-R15	2020s	μ (BCM)	3.75	5.46	7.91	6.41	4.49	3.07	2.36	1.78	1.29	1.04	0.93	1.91	3.34
		σ (BCM)	1.06	1.21	2.07	1.78	1.16	0.79	0.59	0.43	0.28	0.19	0.19	0.61	2.41
		CV (%)	28.20	22.11	26.18	27.70	25.83	25.92	25.18	23.82	21.35	18.63	20.14	32.04	72.31
HadCM2	2080s	μ (BCM)	2.69	4.07	5.29	4.19	3.04	2.09	1.63	1.26	0.95	0.79	0.72	1.14	2.31
		σ (BCM)	0.69	0.84	1.20	1.02	0.73	0.50	0.37	0.26	0.16	0.11	0.10	0.28	1.60
		CV (%)	25.50	20.51	22.71	24.35	24.04	23.94	22.51	20.46	17.31	14.02	14.51	24.32	69.24
HadCM2-S	2080s	μ (BCM)	2.35	3.62	4.54	3.72	2.78	1.93	1.52	1.19	0.90	0.76	0.69	1.07	2.07
		σ (BCM)	0.58	0.71	0.98	0.90	0.67	0.46	0.34	0.24	0.15	0.10	0.09	0.25	1.37
		CV (%)	24.57	19.64	21.61	24.21	24.20	23.95	22.41	20.23	16.91	13.54	13.64	23.01	65.89
ECHAM4	2080s	μ (BCM)	3.04	4.74	6.96	5.60	3.94	2.67	2.05	1.55	1.13	0.90	0.83	1.61	2.89
		σ (BCM)	0.81	1.00	1.76	1.51	1.00	0.68	0.50	0.35	0.22	0.15	0.15	0.49	2.10
		CV (%)	26.76	21.12	25.35	26.90	25.39	25.39	24.39	22.71	19.73	16.29	18.12	30.41	72.60

Table A.7: Monthly flow variation for all GCM scenarios

Scenario	Years	Measure	Month												Annual
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Base	61-90	μ (GWh)	938.38	1060.07	1190.40	1152.00	1159.04	979.73	777.50	569.66	411.10	331.84	316.46	542.34	780.34
		σ (GWh)	210.64	81.47	0.00	0.00	90.46	215.34	219.48	142.20	86.01	61.24	67.99	138.67	350.29
		CV (%)	22.45	7.69	0.00	0.00	7.80	21.98	28.23	24.96	20.92	18.45	21.48	25.57	44.89
HadCM2	2020s	μ (GWh)	830.39	1059.77	1182.34	1136.17	1087.75	839.02	629.14	473.55	349.18	286.65	268.76	457.99	711.57
		σ (GWh)	199.35	80.45	40.52	71.86	158.18	233.49	164.79	104.62	67.10	46.71	49.01	127.91	358.52
		CV (%)	24.01	7.59	3.43	6.32	14.54	27.83	26.19	22.09	19.22	16.30	18.24	27.93	50.38
HadCM2-S	2020s	μ (GWh)	846.89	1063.57	1183.83	1138.97	1117.88	886.40	649.29	492.14	361.94	295.29	276.07	483.05	727.23
		σ (GWh)	203.00	62.61	34.77	67.73	144.40	251.97	170.81	108.77	70.10	48.80	51.17	138.19	358.71
		CV (%)	23.97	5.89	2.94	5.95	12.92	28.43	26.31	22.10	19.37	16.52	18.54	28.61	49.33
ECHAM4	2020s	μ (GWh)	896.24	1059.39	1190.40	1152.00	1156.67	957.56	749.16	541.18	392.54	315.36	315.28	521.79	766.01
		σ (GWh)	204.38	85.16	0.00	0.00	96.56	228.27	216.78	128.67	79.82	55.54	70.12	131.41	353.25
		CV (%)	22.80	8.04	0.00	0.00	8.35	23.84	28.94	23.78	20.34	17.61	22.24	25.18	46.12
GFDL-R15	2020s	μ (GWh)	995.96	1060.04	1190.40	1152.00	1161.74	995.15	799.03	574.97	413.60	331.11	297.04	580.66	789.64
		σ (GWh)	199.66	81.65	0.00	0.00	82.55	209.30	232.61	145.34	88.59	61.93	59.98	156.46	354.30
		CV (%)	20.05	7.70	0.00	0.00	7.11	21.03	29.11	25.28	21.42	18.70	20.19	26.95	44.87
HadCM2	2080s	μ (GWh)	767.20	1048.59	1164.55	1103.81	1011.18	708.08	522.78	402.73	302.31	252.79	230.63	366.75	652.25
		σ (GWh)	165.36	102.22	80.09	134.82	217.50	207.09	117.52	82.56	52.48	35.68	33.63	89.19	363.67
		CV (%)	21.55	9.75	6.88	12.21	21.51	29.25	22.48	20.50	17.36	14.11	14.58	24.32	55.76
HadCM2-S	2080s	μ (GWh)	694.14	975.41	1135.89	1044.86	948.63	638.57	488.56	380.11	287.86	242.65	221.25	341.92	613.38
		σ (GWh)	144.29	142.38	128.03	179.45	242.33	172.33	109.73	77.11	48.90	33.05	30.32	78.78	350.61
		CV (%)	20.79	14.60	11.27	17.17	25.55	26.99	22.46	20.29	16.99	13.62	13.71	23.04	57.16
ECHAM4	2080s	μ (GWh)	844.04	1061.75	1190.40	1152.00	1116.50	906.43	681.62	493.21	360.00	286.96	264.34	501.16	732.59
		σ (GWh)	197.56	72.45	0.00	0.00	156.94	240.62	199.11	108.74	71.26	46.98	48.07	132.33	362.05
		CV (%)	23.41	6.82	0.00	0.00	14.06	26.55	29.21	22.05	19.80	16.37	18.18	26.40	49.42

Table A.8: Monthly production variation for all GCM scenarios

Measure	Base 1961-90	HadCM2 2020s	HadCM2-S 2020s	ECHAM4 2020s	GFDL-R15 2020s	HadCM2 2080s	HadCM2-S 2080s	ECHAM4 2080s
NPV ($ million)	98.07	9.64	31.20	76.12	110.20	-66.33	-116.73	37.23
IRR (%)	11.00	10.10	10.30	10.75	11.10	9.25	8.65	10.35
Unit Cost (USc/kWh)	1.52	1.66	1.63	1.55	1.50	1.80	1.92	1.62
Payback (Years)	7.33	8.00	7.92	7.58	7.25	8.83	9.67	7.83
Disc. Payback (Years)	20.42	29.17	26.00	21.83	19.83	>30.00	>30.00	25.5
ROI (%)	17.27	15.48	15.88	16.87	17.51	13.92	12.91	16.02
Benefit-Cost ratio	1.10	1.01	1.03	1.08	1.11	0.93	0.88	1.04

Table A.9: Financial performance for GCM scenarios

A.4 Implications of Climate Change

The data in this section refer to figures quoted in Chapter 8, regarding the implications of the climate scenarios on issues ranging from replacement energy to emissions.

Table A.10 shows the impact of a 10% shortfall in hydro production resulting from a combination of reduced output or reduced capacity. Replacement energy is assumed to be available at \$30/MWh (in real terms), capacity is based on a 65% load factor, and investment cost on \$1200/kW installed for a coal station.

Measure	
Mean Annual Hydropower Production (TWh)	4,137
Mean Annual Deficit (TWh)	414
Mean Annual Replacement Energy Cost (\$B)	12.4
Mean Annual Additional Emissions (Mt CO_2)	250
Annual Deficit in 2100 (TWh)	750
Additional Capacity Required 2000-2100 (GW)	131.8
Investment Cost (\$B)	158
Cumulative Emissions by 2100 (Gt CO_2)	25

Table A.10: Global implications of a 10% reduction in hydropower production

For Table A.11 equivalent capacity is on the basis of a 65% load factor, and construction costs and emissions refer to a coal fired station with standard technology available in 2000. Replacement energy costs refer to imports at 1.82 US c/kWh, and Base production is 9,364 GWh per year. Figures in parantheses indicate gains.

		Energy (GWh/yr)	Deficit (GWh)	Replacement Cost ($M/yr)	Equivalent Capacity (MW)	Construction Cost ($m)	30 year Emissions (Mt CO_2)	Abatement Cost ($/t CO_2)
HadCM2	2020s	8,539	824	15.0	145	174	24.7	4.48
HadCM2-S	2020s	8,727	637	11.6	112	134	19.1	4.39
ECHAM4	2020s	9,192	171	3.1	30	36	5.1	4.17
GFDL-R15	2020s	9,476	(111)	(2.0)	(20)	(30)	(3.3)	4.05
HadCM2	2080s	7,827	1,536	27.9	270	324	46.1	4.90
HadCM2-S	2080s	7,361	2,004	34.5	352	422	60.1	5.21
ECHAM4	2080s	8,791	581	10.6	102	122	17.4	4.36

Table A.11: Summary of climate change implications for Zimbabwe

A.5 Data Sources

Batoka Gorge Feasability Study

Permission for access to the Batoka Gorge Feasability Study was given by the Zambezi River Authority, and was viewed at the offices of Knight Piésold Ltd. Their contact details are as follows:

Zambezi River Authority	Knight Piésold Ltd
Kariba House	Station Road
32 Cha Cha Cha Road	Ashford
P.O. Box 30233	Kent
Lusaka	TN23 1PP
Zambia	UK

Observed Climate Data

Monthly mean data for 1961-1990 and times series data for 1901-1995 available from the IPCC Data Distribution Centre hosted by CRU at:

`http://ipcc-ddc.cru.uea.ac.uk/`

GCM Scenarios

Scenario data and and Global Visualisation (Figures 8.1 and 8.2) available from the IPCC Data Distribution Centre hosted by CRU at:

`http://ipcc-ddc.cru.eua.ac.uk/`

Appendix B

Publications

The work described in this thesis has been reported in the following publications :

[B1] Harrison, G.P., Whittington, H.W. and Gundry, S.W. 'Climate Change Impacts on Hydroelectric Power', Proceedings of the 33rd Universities Power Engineering Conference (UPEC '98), Napier University, Edinburgh UK, 8-10 September 1998, pp. 391-394.

[B2] Harrison, G.P. and Whittington, H.W. 'Hydropower Investment Appraisal and Climate Change', The Postgraduate Journal of the Department of Electronics and Electrical Engineering (PhDEEE), Issue 6, Department of Electronics and Electrical Engineering, University of Edinburgh, June 2000, pp. 44-48.

[B2] Harrison, G.P. and Whittington, H.W. 'Impact of climatic change on hydropower investment', 4th International Conference on Hydropower Development (Hydropower 2001), Bergen, Norway, 19-22 June 2001 (in press).

B.1 33rd Universities Power Engineering Conference

CLIMATE CHANGE IMPACTS ON HYDROELECTRIC POWER

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ABSTRACT

Anthropogenic emissions of greenhouse gases are expected to lead to significant changes in climate over the next century. One of the many potential effects is that river catchment runoff may be altered. This could have implications for the design, operation and viability of hydroelectric power stations. This describes attempts to predict and quantify these impacts. It details a methodology for computer based modelling of hydroelectric resources and proposes analysis of the impacts on the electrical system and on the investment performance of hydro.

INTRODUCTION

Climate change or global warming is the expected outcome of increases in atmospheric concentrations of "greenhouse" gases resulting from human activities. Many greenhouse gases, including carbon dioxide (CO_2), occur naturally and keep the earth warm by trapping heat in the atmosphere. However, since the Industrial Revolution, anthropogenic sources of CO_2 have added greatly to the atmospheric concentrations, and in particular, transportation and the burning of fossil fuels for electricity generation are frequently cited as major sources. Other man-made greenhouse gases, such as CFC's, are believed to exacerbate the process. Enhanced levels of greenhouse gas concentrations are predicted to cause a significant rise in temperature over the next century. The rates of increase are anticipated to be greater than at any time in the past. The current scientific consensus is that under present rates of economic and population growth global mean temperatures will rise by 3°C by the end of the next century. This is expected to be accompanied by increases in global precipitation levels of 15% [1].

Predictions of future climate are based on the output of complex numerical Global Circulation Models (GCM's) which simulate physical processes in the atmosphere and oceans. A number of research groups have developed GCM's including the UK Meteorological Office (UKMO), the Geophysical Fluid Dynamics Laboratory (GFDL) at Princeton University, and NASA's Goddard Institute for Space Studies (GISS). Although different GCM's simulate current climate with varying degrees of precision most agree on the general trends.

The main technique for avoiding the worst extremes of climate change is to limit the increase in greenhouse gas concentrations by reducing emissions. As electricity production is responsible for a significant portion of the emissions, much of the burden will fall on the energy sector. Possible measures include transferring to lower carbon fuels like natural gas, together with increased use of renewable energy sources including hydropower [1].

Hydropower is an attractive energy source as it is renewable with minimal operational emissions of greenhouse gases. In addition, there are no fuel charges and the civil works have a long useful life. However, large dams may necessitate population displacement and can impact on the ecology of the basin [2, 3]. Exploitation of hydropower potential is considered by many governments and international bodies to be a key feature in economic development, especially in less developed countries (LDC's).

At first glance, increased global precipitation would appear to suggest more water available for hydroelectric power production. However, higher temperatures will lead to increased evapotranspiration levels. Whether increased global precipitation is seen as increased river runoff depends on the regional climate and hydrology. In the past, feasibility studies have relied on historical rainfall and river flow data for the assessment of hydroelectric potential at a proposed site. However, climatic change means that these can no longer be relied on to indicate future potential [2]. It is perhaps ironic to consider that attempts to reduce climatic change by switching to non-fossil fuels could be hampered by the legacy of their use.

CLIMATE CHANGE IMPACTS ON HYDROPOWER AND ENERGY SECTORS

Changes in the quantity and timing of river runoff, together with increased reservoir evaporation will have a number of effects on the production of hydroelectric power. These include impacts upon system operation, financial effects and impacts on other energy sectors.

System Operation and Development

Changes in the availability of existing hydroelectric plant, together with system constraints will affect the ability of the electricity supply system to meet average and peak demands. In the longer term, as demand levels increase, system planning may have to address any predicted shortfall in hydro output by constructing additional generating plant [4]. The likelihood is that fossil fuels will be used, further enhancing radiative forcing [2]. Climate change may also result in some planned projects being cancelled or adapted.

Financial Effects

Hydroelectric stations are characterised by low operational costs but high capital costs. Generally, revenue from electricity sales is the only way of servicing the capital debt. Thus reductions in electricity sales will affect the return on investment and hence the viability of the plant [2]. The loss of hydroelectric generating capacity will require additional plant to be constructed to meet demand, requiring additional capital and thus reducing overall system returns.

Many large hydropower developments in LDC's are built with the intention of stimulating economic development. Generally, this requires international financing with a requirement for the loan repayments to be in hard currency. Reductions in revenue may affect the ability to repay the hard currency debt and this may severely stress a weak economy. In addition, the fall in electricity availability will hamper Governments' attempts to aid economic development.

Effects on other Energy Sectors

Climate change will have impacts on both electricity demand and supply. Higher air temperatures will tend to lower winter heating demands but increase summer cooling demand. Thermal generating stations requiring rivers for cooling water may suffer operational constraints due to reduced river flows [2, 5, 6]. Warmer river and sea water will reduce the efficiency of steam cycles, resulting in lost output or increased fuel consumption. Predicted sea level rise may also threaten coastal stations; climate change may lead to more extreme weather patterns causing increased system damage costs. Climate change may affect other renewable technologies: wind patterns may change as a result of changed temperature gradients, and changes in cloud cover may affect the performance of solar panels [7].

CLIMATE IMPACTS ASSESSMENT

The potential impact of climate change on water resources has been suggested since the 1980s, as work progressed on predicting climate change [5]. Although GCM's can be used to predict runoff directly, the coarse scale used means that this information is only useful for the most general studies. As a result, many studies have been carried out on individual basins, showing that river basins display a range of sensitivities to climate change [8]. Figure 1 shows the response of a typical river basin to variations in precipitation and temperature. It can be seen that increased temperature results in non-linear variations in runoff due to changes in precipitation.

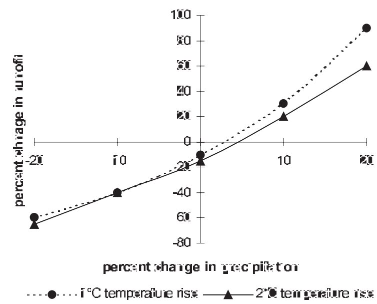

Figure 1: River Basin Response To Climate Change

Later studies have considered not only the effect on river flows but also the impact on generation from hydroelectric stations [9]. In particular, one study examined a number of international river basins [4]. The study drew upon existing hydrological and dedicated basin models and the experience of international experts. For example, for one GCM scenario (GFDL), hydroelectric production on the Indus River would fall by 22%. Another study [2] qualitatively examined the effects of reduced hydroelectric output on sub-Saharan Africa and central Europe. However, to date, studies have failed to quantify the impacts in terms of the investment performance of plant or on the electrical network.

Modelling Impacts

Climate impact assessment requires scenarios of future climate to be translated into potential changes on natural and human systems. To assess climate impacts on hydropower production a number of key steps must be taken [4]:

1. A river basin is selected and its rainfall-runoff processes are modelled and calibrated;
2. Climate data emanating from different GCM or arbitrary climate scenarios is applied to the model and the runoff computed;
3. River runoff values are converted into estimates of hydroelectric power production.

The first step involves the accurate modelling of the hydrology of the chosen river basin. A wide variety of modelling techniques have been applied to simulating runoff processes [10]. Three basic approaches exist:

- Empirical
- Conceptual
- Deterministic

The first type requires a relationship to be established between climate inputs (e.g. rainfall) and hydrological outputs (i.e. runoff). The second type uses a simplified representation of the physical processes to mimic the storage and flow of water. The technique requires such models to be calibrated for each catchment using relevant climate and river flow data. The final approach is based on complex physical theory and most examples are spatially distributed in two or three dimensions. Such models claim to give a more explicit representation of hydrological processes, but suffer from the requirement for significant quantities of information for operation.

Despite the sophistication of current hydrological modelling techniques, particular difficulties exist in translating the GCM's large spatial and temporal predictions into a form that can be used by a hydrological model. Techniques to overcome this are termed downscaling methods [5], and attempt to generate local values for precipitation (say) from the large-scale GCM values. Other methods include nesting smaller-scale regional climate models inside the GCM's, creating weather stochastically and using analysis of different weather types.

Given that climate data from GCM's can be converted into a form suitable for use, the output from a suitably calibrated hydrological model would be similar to that shown in Figure 2 for present and assumed future climates.

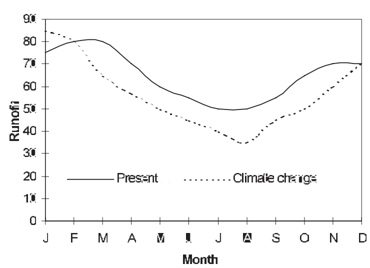

Figure 2: Effect of Climate Change on Runoff

In this hypothetical case it can be seen that climate change affects the magnitude and timing of river runoff. Winter runoff is higher as more precipitation falls as rain rather than snow, the winter thaw occurs earlier, and summer runoff is also lower.

The potential for hydroelectric generation approximately follows runoff, so it can be seen that hydroelectric potential would also be affected. A more accurate estimate of climate impacts on hydropower would involve assessment of the relative importance and cost of hydro, the economic development of the country and the policies of governments and international organisations.

PROPOSED COMPUTER MODEL

This work is concerned primarily with the design and development of a generic hydropower assessment tool suitable for use with any hydropower scheme and relevant climate scenario. The assessment tool will be implemented on a PC and would consist of:

A (simple) self-calibrating hydrological model that would be able to derive suitable input-response relationships, given suitable climate and river flow data. After calibration, the model will convert input climate data into estimates of river flows. These results would be processed by the hydropower component, which when given suitable technical and operational parameters, would compute the electrical power generated.

With this structure, the model will give indications of the power generated for desired baseline and predicted climate scenarios. This will enable projections to be made concerning the investment performance of the hydroelectric scheme together with assessments of the impact on the economy. In addition, the generation scenarios may be used for analysis of the electrical system, in terms of its generation mix and overall power requirements.

A simplified model may be as effective as a more complex one given that at present climate data from GCM's is available in terms of mean monthly values. Accordingly, monthly river flows are likely to be more meaningful than shorter time frames. Although this time step is too long to allow simulation of hydro-plant scheduling, suitable operational rules can be derived to mimic its output.

In general, consideration of hydropower impacts has been concerned with the potential annual production of electricity and not the impact of changes in the monthly availability. Month-to-month changes in electricity demand are generally greater than year-to-year, so a consideration of the monthly availability is likely to have more relevance. Consideration of spillage and the likely actual production under climate change will allow a more realistic representation.

It is expected that a number of case studies will be carried out using the software tool. These will tend to concentrate on large strategically important hydroelectric power projects both in existence or planned. The majority of such projects are in LDC's highlighted as being sensitive to climate change. Among the areas under consideration are sub-Saharan Africa and East Asia. In particular, the Three Gorges Dam on the Yangtze River in China will be examined, due to its key role in China's economic and water resources development, its sheer size and cost, and the alleged potential for environmental and social catastrophe.

Application of Proposed Software Tool

The proposed software tool would have a number of applications. It would:

- allow planners to make projections of changes in future availability of water and power resources.
- enable water resources and hydropower designers to compare competing schemes before detailed feasibility studies commence.
- allow assessment of the impacts of land use changes.
- interface with existing dedicated basin models to allow accurate water flow projections to be input to the hydropower element of the software.

The key outcome of this work will be information on how hydropower may fare as an investment opportunity, and as a driver of economic development in LDC's.

CONCLUSION

Human activities are expected to lead to substantial changes in climate. One outcome may be reductions in river runoff with potentially serious ramifications for the provision of hydroelectric power. Recent attempts at quantifying these impacts have been described and a methodology proposed to enable analysis of the impact on the electrical system as well as the investment performance of hydroelectric plant.

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B.2 Postgraduate Journal

Hydropower Investment Appraisal and Climate Change

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Abstract

Climate change is expected to have serious consequences for many areas of human activity. One such area is in the exploitation of water resources, and in particular hydropower. The alteration of precipitation and temperature patterns will lead to changes in the quantity and timing of river runoff. This may result in reductions in electrical output and sales revenue, and adversely affect the opportunities for investment in hydropower. This paper addresses the issues involved in, and preliminary results from, an assessment of the viability of hydroelectric developments with changed climate.

1. Introduction

Climatic change is expected to be the outcome of increases in atmospheric concentrations of "green-house" gases resulting from human activities [1]. The emissions are caused, in part, by fossil-fuelled electricity generation, and as world energy demand is expected to at least double by 2050 [2], emissions and hence concentrations are expected to rise considerably. The impact of climatic change could be significant especially if less developed countries (LDCs) expand their electricity supply networks using fossil fuels.

In an attempt to control greenhouse gas concentrations and slow down the greenhouse process, governments are aiming to cut or stabilise emissions relative to 1990 levels. To achieve this target, the energy sector will have to change the way it operates: it could reduce its reliance on fossil-fuels, use more renewable energy, and practice greater energy efficiency. These measures should allow the climate to reach and stabilise at a new equilibrium level.

Over the next century or so, during which this new set of equilibrium conditions will be reached, generating plant could be expected to be replaced twice. Increasing demand and the move to deregulated electricity systems, means that private investment is likely to be used to fund new and replacement capacity. This, in turn, means that the perceptions of current and future investors will play a major role in whether emission cuts are achieved.

2. Climate Change

Many greenhouse gases, including carbon dioxide (CO_2), occur naturally and keep the earth warm by trapping heat in the atmosphere. However, since the Industrial Revolution, man-made sources of CO_2 have added greatly to the atmospheric concentrations. In particular, transportation and the burning of fossil fuels for electricity generation are frequently cited as major sources.

Enhanced levels of greenhouse gas concentrations are predicted to cause a significant rise in temperature over the next century, with rates of increase anticipated to be greater than at any time in the past. The current consensus is that under present rates of economic and population growth, global mean temperatures will rise by around 3°C by the end of the next century, although there is considerable uncertainty surrounding the degree of climate sensitivity. Figure 1 shows that throughout the 20th Century, temperature has been increasing, as has the rate of increase. The rise in temperature is expected to be accompanied by increases in global mean precipitation levels of 3-15% [1].

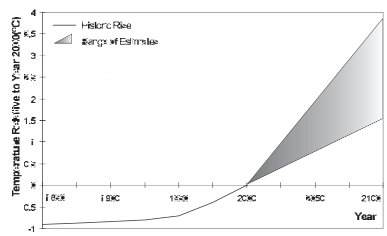

Figure 1: Historic and possible future temperature rise (adapted from [1])

Most predictions of future climate are based on the output of complex numerical Global Circulation Models (GCMs) which simulate physical processes in the atmosphere and oceans. A number of research groups have developed GCMs including the UK Meteorological Office. Although GCMs differ in their simulation of current climate and prediction of future climate, many agree on the general temperature trend [3,4].

There are many potential impacts of climatic change including: loss of land due to sea level rise, damage from increased levels of storm activity, and threats to bio-diversity [1].

Under the Kyoto Protocol [5] most countries agreed that in order to avoid the worst extremes of climate change, they would limit the increase in greenhouse gas concentrations by reducing emissions. As electricity production is responsible for a significant portion of the emissions, much of the burden will fall on this sector. Increased use of renewable energy sources, including hydropower, is one suggested way in which reductions can be achieved.

However, changes in climate may affect renewable sources of power, and frustrate efforts to stave off climate change.

3. Impact on Hydroelectric Generation

At first glance, rising global precipitation would seem to provide opportunities for increased use of hydroelectricity. However, the associated temperature rise will lead to increased evaporation, with changes occurring non-uniformly from region to region. In the river basin, it is the interaction of precipitation and evaporation that determines the water available for runoff. For example, higher temperatures may lead to an earlier spring thaw and lower flow during the summer months. Figure 2 shows a hypothetical example of this [6]:

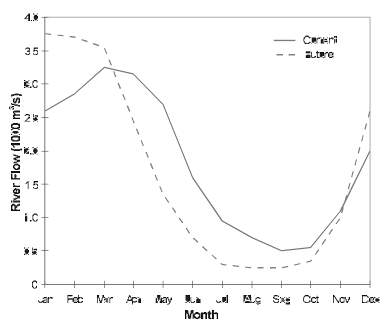

Figure 2: Climate changed runoff

Many studies have considered the hydrological effects of climate change (*e.g.* [7]). A smaller number have examined the impact of changes in the quantity and timing of river runoff, together with increased reservoir evaporation on hydroelectric power production and reliability (*e.g.* [8]). Fewer still have examined how changes in the availability of existing hydroelectric plant, as a result of altered river flow, will affect the ability of the electricity supply system to meet demand [9].

Despite this, no-one has considered the important aspect of the potential impact on the perceived or actual financial performance of hydro stations. Hydro is characterised by low operational costs but high capital costs. As a result, the debt repayment period for a hydro scheme is often significantly longer than for fossil-fuelled plant. Despite high fossil-fuel costs, hydro will often be at a disadvantage, and would not be favoured by short-term orientated investors. As with all generation methods, electricity sales revenue is the only way of servicing the capital debt. If reductions in runoff and output were to lead to reductions in revenue, this would adversely affect the return on investment and hence the perceived attractiveness of the plant.

If potential hydro schemes are abandoned or existing hydroelectric generating capacity is limited due to runoff changes, then the likely alternative is that fossil-fuelled stations will have to be constructed. This would probably result in additional carbon emissions exacerbating climate change, and a requirement for additional capital to be locked into electricity generation [10].

Many large hydropower developments in less developed countries are built with the intention of stimulating economic development. Often, these are internationally financed and repaid in hard currency. Reductions in revenue may make it difficult to repay the debt, severely stressing weak economies, while the shortfall in electricity availability will hamper Governments' development attempts [10].

The net effect is that hydropower could become less attractive to investors, whether private or public, and as a consequence attempts to limit climate change will be frustrated. The different issues involved in the assessment of the viability of hydroelectric developments are now discussed.

4. Investment Appraisal

The issues surrounding hydroelectric projects are generally dealt with in feasibility studies. Whilst a full study would examine the engineering, economic, political and social features, the most important aspect for the investor would be the financial appraisal of the project. It is this aspect that is the focus for the study.

Financial appraisal aims to provide information that allows the investor to decide if a particular investment will provide a suitable return. For electricity generation projects, likely energy output and revenue is assessed and compared with capital and operation and maintenance costs over the planned lifetime of the plant. Hydropower appraisal is slightly different in that its fuel source is not guaranteed, and focuses on the availability of the water resource, through an examination of historic river flows at the site in question. Whilst the plant is designed on the basis of the river flow-exceedance probabilities, estimates of output and hence revenue are often determined by a time series simulation of the plant with assumed operating procedure defining the output. More sophisticated analyses use synthetically generated flow sequences, derived from the historic data, to examine the robustness of the operating procedures and design specifications.

Traditionally, the Generator would receive a fixed price per unit of energy output, which would be inflated annually by an accepted amount. The revenue earned could be estimated from knowledge of the tariff, and predictions of output. Revenue is then set against the costs and standard appraisal techniques are applied to them (*e.g.* Net Present Value (NPV)).

Most medium and large hydro schemes have been built by, or for use on publicly owned and operated electricity systems. As such, hydro has been used for reasons other than pure profit-making, *e.g.* secure electricity supplies, minimisation of overall system operational cost, avoidance of fuel importation or for environmental reasons.

Increasingly, generation schemes are being constructed by private investors selling power to a host Utility, and, as such, the plant is intended to maximise profit potential rather than minimise overall cost.

5. Software Tool

The major objective of this study is to develop a software tool to perform the investment analysis [11]. "HydroCC" (an acronym for "Hydropower and Climate Change") is being implemented using Visual C++. It encapsulates the investment appraisal process, such that, after entering the case study parameters, the user will be presented with key pointers to the potential investment performance of the project under historic and potential future climates.

Although based on the traditional approach, two factors require that changes are made to the process:

1. The possibility of climate change implies that historical river flows cannot be relied on to indicate future flows.
2. The proliferation of deregulated or liberalised power systems world-wide, suggests that traditional analysis may be insufficient to determine the operational and revenue patterns of future projects.

The changes are now addressed in detail.

5.1 Climate to Flow

If future flows can no longer be relied on to follow historic flow patterns, then a link between climatic variables and river flows is required. This requirement can be met by the use of hydrological models. Despite its maturity, hydrological modelling is still an inexact science, due to the complexity of the natural system and difficulties in measurement of key climatic variables. Statistical models do exist but suffer from the limitation that in a future where climate changes, current statistical relationships may not hold. A more robust approach is to base the model on actual physical processes [6]. In this application, data is scarce and so a simple water-balance model is used. Many examples exist, but all attempt to simulate a river basin as a series of storage zones, with mathematical descriptions of flow processes in and out of the storage. The model incorporated in the software is a well known model known as WATBAL [12]. It takes suitable spatially-averaged climate data and transforms it into river flow. As shown in Figure 3, WATBAL represents the river basin as a single unit of soil storage, and water enters and leaves the storage in a number of different ways, through: precipitation, evaporation and runoff.

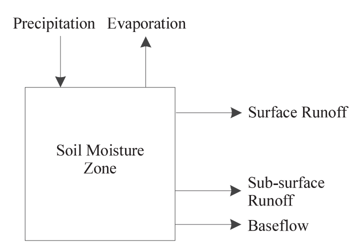

Figure 3: WATBAL structure [13]

The system is modelled as a differential equation in order that different time-steps can be used [13]:

$$S_{MAX}\frac{dz}{dt} = P(t) - ET(z,t) - R(z,t) \qquad (1)$$

where P is precipitation, ET is evapotranspiration, R is total runoff, S_{MAX} is the maximum soil water holding capacity, and z the relative soil moisture depth. It is solved numerically using the Runge-Kutta method [14]. The model has several parameters that require calibration. This will be carried out by a Genetic Algorithm that attempts to match simulated and historic runoff. In an attempt to imitate the sophisticated multiple-series analysis of the traditional appraisal, synthetic series of key climate variables (*i.e.* precipitation, temperature) can be generated and applied to the model.

5.2 Private Capital and Deregulation

The increasing involvement of private capital in the electricity supply industry has implications for how existing and potential generation is financially appraised. There are a number of instances where analysis would be required, including:

- Where an investor envisages potential for additional capacity,
- Where a Generator is considering asset disposal,
- Where the asset owner is considering plant refit.

With many electricity industries considering or undergoing liberalisation, it may be necessary to use more sophisticated methods of determining revenue rather than simply to assume a tariff. With competitive markets, prices are not constant over time and vary hour-to-hour. As such, the revenue the Generator receives depends on how it sells its electricity [15]:

1. Through a wholesale market or Pool, where generating units are scheduled on their declared bid price, with the market price set by the marginal generator. Revenue varies according to the demand level and competitors bids.
2. Via bilateral power purchase contracts that specify an agreed price and quantity per period. Often the contracts involve 'hedging' to reduce exposure to market price changes.

A Pool system was implemented in the UK as part of the privatisation process. However, it will shortly be superseded by a system of bilateral contracts.

To estimate revenue in a market it is necessary to predict prices. The use of historic market data is a reasonable method of predicting future price behaviour, but it is limited by a number of factors: difficulties in predicting the generation mix (which determine prices) over the appraisal period; data may not be available if the market is new or non-existent. Simulating market operation avoids some of these problems, but is problematic due to the time-step mismatch between market operation and climate data (sub-hourly versus monthly). Whilst a weighted-average price could be used, the fuel constraint on hydro means that the plant may not be able to operate all the time, and would limit its application.

The problems associated with market modelling are serious and their solution is beyond the scope of this study. Fortunately, many case studies are located in regions that have not deregulated. Even in those that have, lenders will insist on some form of Power Purchase Agreement to reduce price risk. As such it will be possible to assume a tariff for most case studies.

5.3 Modified Appraisal Process

These two changes lead to the process shown in Figure 4, below. The reservoir model used in this application is based on the US Army Corps of Engineers HEC-5 model [16], whilst the electricity market is capable of simulating a variety of market structures.

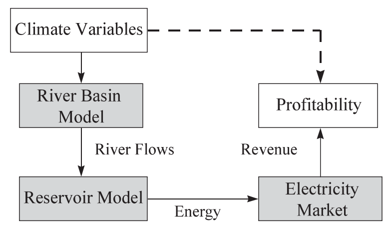

Figure 4: Modified appraisal process

6. Preliminary Results

To illustrate the use of the software tool and give an indication of the type of information that is sought, an appraisal was carried out for a hypothetical hydro scheme (based loosely on the Three Gorges Dam, China). Hypothetical changes in precipitation and temperature relative to a base climate were applied to the model.

It was found that runoff and consequently production and Net Present Value were more sensitive to precipitation change than temperature rise. Figure 5, shows that the relationship between precipitation and both production and NPV is non-linear. It also implies that economic performance is more sensitive to climate change than production. In the worst case considered (precipitation down 30% and 3°C temperature rise) the discounted payback time extends to over 30 years, beyond the assumed economic life of the plant, whilst production drops 70%.

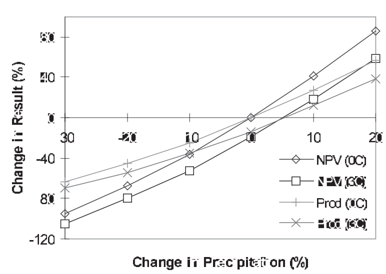

Figure 5: Changes in production and NPV with precipitation and temperature rise.

7. Conclusion

Changes in precipitation and temperature resulting from man-made emissions of greenhouse gases will alter river flows. This may reduce output from hydroelectric power stations, and consequently lower the financial return. With the increasing involvement of private capital in the electricity supply industry, the perceptions of investors are of critical importance, and as such a lower potential return may discourage investment in hydropower. The investment appraisal process is outlined, along with details of how it must be adapted to take account of climate change and electricity industry liberalisation. The results of a preliminary study are presented, which indicate that with precipitation decreases of around 30%, serious falls in production occur (up to 70%), and as a consequence the economic viability of the installation would be compromised.

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Impact of climatic change on hydropower investment

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ABSTRACT: The increased use of renewable energy is critical to reducing emissions of greenhouse gases in order to limit climatic change. Hydropower is currently the major renewable source contributing to electricity supply, and its future contribution is anticipated to increase significantly. However, the successful expansion of hydropower is dependent on the availability of the resource and the perceptions of those financing it. Global warming and changes in precipitation patterns will alter the timing and magnitude of river flows. This will affect the ability of hydropower stations to harness the resource, and may reduce production, implying lower revenues and poorer returns. Electricity industry liberalisation implies that, increasingly, commercial considerations will drive investment decision-making. As such, investors will be concerned with processes, such as climatic change, that have the potential to alter investment performance. This paper examines the potential impact of climatic change on hydropower investment. It introduces a methodology for quantifying changes in investment performance, and presents preliminary results from a case study. These inform discussion of the implications for future hydropower provision and our ability to limit the extent of climatic change.

1 INTRODUCTION

Climatic change is expected to be the outcome of increases in atmospheric concentrations of "greenhouse" gases resulting from human activities (Houghton et al., 1990). The emissions are caused, in part, by fossil-fuelled electricity generation, and as world energy demand is expected to at least triple by the end of the twenty-first century (Nakicenovic et al., 1998), emissions and hence concentrations are expected to rise considerably. The impact of climatic change could be significant especially if less developed countries expand their electricity supply systems using fossil fuels.

In an attempt to control greenhouse gas concentrations and slow down the greenhouse process, governments are aiming to cut or stabilise emissions relative to 1990 levels. To achieve this target, the energy sector will have to change the way it operates: it could reduce its reliance on fossil fuels, use more renewable energy, and practice greater energy efficiency. Together with other means, such measures should allow the climate to reach and stabilise at a new equilibrium level.

Over the next century or so, during which this new set of equilibrium conditions will be reached, generating plant could be expected to be replaced twice (the design life of the electro-mechanical equipment in a power station is rarely greater than 50 years). Increasing demand and the move to deregulated electricity systems means that private investment is likely to be used to fund new and replacement capacity. This, in turn, means that the perceptions of current and future investors will play a major role in whether emission cuts are achieved.

2 CLIMATE CHANGE

Many greenhouse gases, including carbon dioxide (CO_2), occur naturally and keep the earth warm by trapping heat in the atmosphere. However, since the Industrial Revolution, man-made sources of CO_2 have added greatly to atmospheric concentrations. In particular, transportation and the burning of fossil fuels for electricity generation are frequently cited as major sources.

Enhanced levels of greenhouse gas concentrations are predicted to cause a significant rise in temperature over the next century, with rates of increase anticipated to be greater than at any time in the past. The current consensus is that under present rates of economic and population growth, global mean temperatures will rise by around 3 C by the end of the next century, although there is considerable uncertainty surrounding the degree of climate sensitivity. Figure 1 shows that throughout the twentieth century, temperatures have been rising and that the rate of increase is accelerating. The rise in temperature is expected to be accompanied by increases in global mean precipitation levels of up to 15% (Houghton et al., 1990).

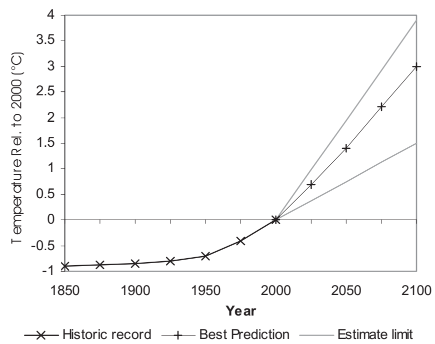

Figure 1. Historic and future temperature rise (adapted from Houghton et al., 1990)

Many predictions of future climate are based on the output of complex numerical General Circulation Models (GCMs) which simulate physical processes in the atmosphere and oceans. Although GCMs differ in the detail of their methodologies, most agree on the general temperature trend (Gates et al. 1990, Wood et al. 1997).

There are many potential impacts of climatic change including: loss of land due to sea level rise, damage from increased levels of storm activity, and threats to bio-diversity (Houghton et al., 1990).

Under the Kyoto Protocol (UNFCCC, 1998) most countries agreed that they would limit greenhouse gas emissions. As electricity production accounts for a significant portion of the emissions, much of the burden will fall on this sector. Increased use of renewable energy sources, including hydropower, is one suggested way in which the emissions targets can be met.

Unfortunately, the very fact that renewable energy resources harness the natural climate means that they are at risk from changes in climatic patterns. As such, changes in climate due to higher greenhouse concentrations may frustrate efforts to limit the extent of future climatic changes.

3 CLIMATE IMPACTS

Hydropower is currently the only major renewable energy source contributing to global electricity supply. Given the expectation of a threefold increase in hydropower production over the next century, the continuing significant contribution from hydropower warrants a closer investigation of the potential impacts of changing climate on hydro.

3.1 *River Flows*

At first glance, rising global precipitation would seem to provide opportunities for increased use of hydroelectricity. Unfortunately, such increases will not occur uniformly over time or space, and many regions are projected to experience significant reductions in precipitation. In addition, the temperature rise will lead to increased evaporation. The combination of changes in precipitation and evaporation will have profound effects on catchment soil moisture levels. The soil provides storage and regulates runoff regimes. Drier soil absorbs more rainfall, tending to reduce the quantity of water available for runoff, while more saturated soils absorb less rainfall increasing the likelihood of flooding.

In river basins that experience significant snowfall, higher temperatures will tend to increase the proportion of wet precipitation. This may increase winter river flows, lead to an earlier spring thaw and reduce summer low flows (Gleick, 1986). Figure 2 shows a hypothetical example of this.

Climate change impacts studies have, in general, relied on rainfall-runoff models to translate changes in precipitation and temperature into altered river flows. GCMs provide information on how climatic variables may change in the future. Unfortunately, each GCM tends to predict a different change in temperature and precipitation, which results in significant and often contradictory differences between resulting river flow impacts. An alternative is to examine basin sensitivity to changing climate, through the application of uniform changes in precipitation and temperature.

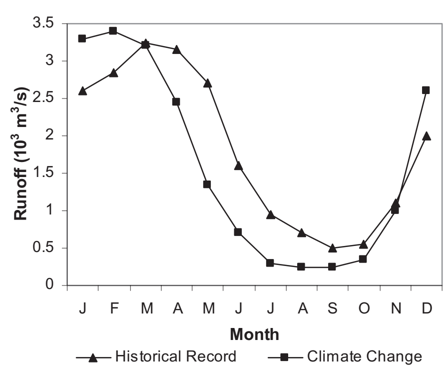

Figure 2. Hypothetical runoff patterns under current and potential climate change scenarios

A significant body of knowledge exists regarding the impact of climate change on river flows (e.g. Gleick, 1986; Arnell & Reynard, 1996). Many suggest significant sensitivity to climate change.

Reibsame et al. (1995) examined climate impacts on several major rivers. For the Zambezi, GCM scenarios suggested that mean annual runoff may decline by 17% or rise by 18%. The most severe change occurred with the Nile which under one scenario mean flows fell to less than a quarter of their historic level. Overall, Reibsame et al. (1995) note that river basin sensitivity increases with aridity, and this, to some degree, explains the severe fall in Nile flows.

Despite differences between the study techniques used and river basin characteristics, Arnell (1996) drew the following conclusions:

1 Runoff is relatively more sensitive to precipitation change than temperature change.
2 River basins tend to amplify changes in precipitation.

Whilst changes in annual runoff are a useful indicator, often the seasonal changes are more profound. For example, Mimikou et al. (1995) found that for the Mesohora basin in Greece a 20% fall in precipitation accompanied by a 4 C temperature increase resulted in a 35% reduction in annual runoff. However, the impact on summer flows was almost twice as large, and the fall in winter was limited to 16%. This pattern is repeated in many other studies and is a result of changes in soil moisture content.

3.2 *Hydroelectric Generation*

Hydropower potential is defined by the river flow, and therefore changes in flow due to climate change will alter the energy potential. More importantly, as most hydropower schemes are designed for a particular river flow distribution, plant operation may become non-optimal under altered flow conditions.

The capability of a given hydro installation to generate electricity is limited by its storage and turbine capacities. These place limits on the amount of carry-over storage to allow generation during dry spells, and also the degree to which benefit can be derived from high flows.

A number of studies have examined the impact of climate change on hydropower production (those listed in Table 1 are a representative sample). Published results suggest that the climate sensitivity of energy production is related to the storage available: in general terms the greater the degree of storage the lower the sensitivity. Additionally, turbine capacity limits the ability of schemes to take advantage of higher flows.

Other than energy volumes, the impact on generation reliability has been examined in a number of studies (e.g. Mimikou & Baltas, 1997). Garr & Fitzharris (1994), among others, relate both hydropower production and energy demand to climatic variables in their examination of how climate change will affect the ability of the electricity supply system to meet demand.

Table 1. Examples of potential changes in annual hydro generation resulting from changes in temperature and precipitation.

Region/River	Temperature	Precipitation	Production
Nile River*	+4.7 C	+22%	-21%
Indus River*	+4.7 C	+20%	+19%
Colorado River **	+2.0 C	-20%	-49%
New Zealand ***	+2.0 C	+10%	+12%

Notes: * Reibsame et al. (1995), ** Nash & Gleick (1993), *** Garr & Fitzharris (1994).

3.3 *Revenue and finance*

Despite such studies, none published to date has quantified the potential impact on the perceived or actual financial performance of hydro stations.

Hydro is characterised by low operational costs but high capital costs. As a result, the debt repayment period for a hydro scheme is often significantly longer than for fossil-fuelled plant. Despite high fossil-fuel costs, hydro will often be at a disadvantage, and would not be favoured by short-term orientated investors. As with all generation methods, electricity sales revenue is the only way of servicing the capital debt. If reductions in runoff and output were to lead to reductions in revenue, this would adversely affect the return on investment and hence the perceived attractiveness of the plant. Therefore, there is a possibility that potential schemes would not be pursued.

If potential hydro schemes are abandoned or production from existing facilities is limited by runoff changes, then the likely alternative is that fossil-fuelled stations will have to be constructed to cover the deficit. Not only would this require additional capital to be used, but also would probably result in additional carbon emissions, thus exacerbating climate change (Whittington & Gundry, 1998).

Many large hydropower developments in less developed countries have been built with the intention of stimulating economic development. Often, these are internationally financed and repaid in hard currency. Reductions in revenue may make it difficult to repay the debt, severely stressing weak economies, while the shortfall in electricity availability will hamper Governments' development attempts (Whittington & Gundry, 1998).

The magnitude of capital investment required for hydropower installations, together with the increasing penetration of private capital in the industry makes it imperative that project analysis takes account of potential climatic effects.

4 INVESTMENT APPRAISAL

To assess the threat that climate change poses to future hydropower investment, there is a requirement for a robust methodology. The diverse nature of hydropower installations and climatic conditions precludes any form of accurate regional or global analysis at this stage. Therefore, an analysis on a case by case basis is necessary.

To assess the impact on investment it is necessary to consider the problem from the standpoint of a potential investor. They will be primarily concerned with the impact on a range of investment indicators, and, as such, a methodology derived from traditional hydropower appraisal was devised.

The techniques of hydropower appraisal are long established. However, the continuing reliance on historic flows to indicate future flow conditions is not prudent given the prospect of climate change. Some recent project appraisals have attempted to deal with climate change by uniformly altering river flows. Unfortunately, this practice is inadequate as it fails to take into account the tendency of a river basin to amplify precipitation changes.

The complexity of the task necessitates a software tool, the basic specifications for which are introduced elsewhere (Harrison et al., 1998) and illustrated schematically in Figure 3. The use of a rainfall-runoff model removes the reliance on historic flows by providing a link between climatic variables and river flows. This enables the relationship between climate and financial performance to be examined effectively.

The rainfall-runoff model is calibrated using monthly historic river flow and climate data. Following this, suitable operational, financial and economic data enables simulations to be rapidly carried out.

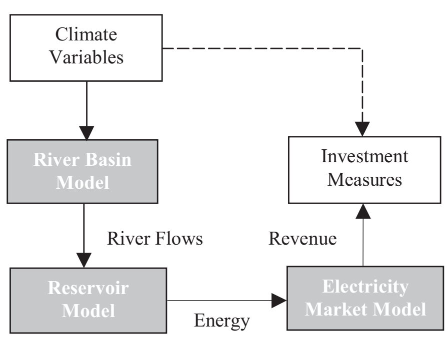

Figure 3. Software tool structure.

5 RESULTS

Software has been developed by the authors to meet the required specifications. The software was tested using an actual planned scheme: sample results are presented here. The chosen scheme has limited reservoir storage capacity and is intended to operate as a run-of-river plant. The river flow regime is highly seasonal and is not influenced by snowfall. Basic operational and financial information was extracted from a traditional feasibility study of the scheme. Simulations indicated that the software delivers production estimates and investment measures that are comparable with figures found in the feasibility study.

A sensitivity study was carried out with the model driven by historic precipitation and temperature data uniformly changed to simulate climate change. Results suggested that runoff and energy production are sensitive to rainfall change, and that runoff changes are significantly greater than the precipitation variation. Although storage is limited, production sensitivity is lower than runoff. Energy production is less sensitive to increases in flow as much of the excess flow is spilled.

The assumption of a single energy price means that the investment sensitivity follows a similar pattern to production. Figure 4 shows the response of internal rate of return (IRR) and discounted payback to rainfall variations. IRR is positively related to rainfall, whilst discounted payback period shows the opposite trend. The greater sensitivity to flow reductions can be seen.

Net present value is not shown in Figure 4 as the NPV variations significantly larger. The compounding effect of revenue changes over the project lifetime means that NPV ranges from -200% to 140%.

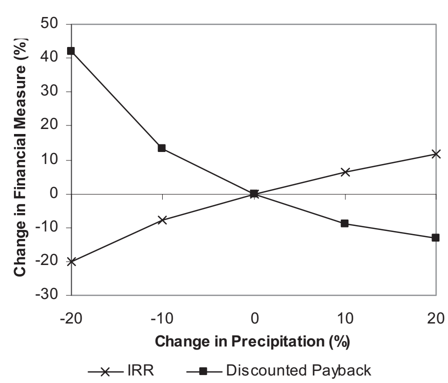

Figure 4. Sensitivity of financial appraisal measures to uniform changes in precipitation

Although these results are only preliminary, they indicate that the financial performance of the scheme is sensitive to rainfall changes. Furthermore, they imply that in regions that experience reduced rainfall, hydropower could become less competitive. As such, investment in hydropower projects will be less likely, and the ability to limit climate change will be reduced.

6 CONCLUSIONS

Climatic change is expected to result from the release of significant quantities of man-made emissions of greenhouse gases. One of the key methods of limiting the extent of change is through the use of renewable energy sources, including hydropower. Unfortunately, the reliance of hydropower on climatic conditions means that the changes predicted may affect it adversely. In particular, and given the increasing importance of private capital within the electricity industry, the financial performance of hydro schemes may be damaged. Subsequently, hydropower will be less competitive and alternative, presumably fossil-fuelled schemes will take precedence, reducing our ability to reduce greenhouse gas emissions.

A range of impacts on river flows and hydropower production have been identified, together with a consideration of the potential consequences of failing to take account of climate change when planning hydro schemes. A methodology and associated software tool have been briefly introduced which enable quantification of changes in investment performance as a result of changes in climate. Preliminary results of its use on a planned scheme are presented. The results indicate that investment measures show significant sensitivity to changes in rainfall. This implies that in regions that experience reductions in rainfall, hydropower will become less competitive. Therefore, investment in hydro projects is less likely to occur and our ability to control greenhouse emissions is lessened.

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